OLD NATIONAL BANCORP /IN/
Form 4
July 11, 2017

FORM 4

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

OMB APPROVAL	
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STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

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

(Print or Type Responses)

1. Name and Address of Reporting Person *
Skillman Rebecca S

(Last) (First) (Middle)

ONE MAIN ST

(Street)

EVANSVILLE, IN 47708

(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
OLD NATIONAL BANCORP /IN/ [ONB]

3. Date of Earliest Transaction (Month/Day/Year)
06/15/2017

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

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

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

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

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

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			
COMMON STOCK	06/15/2017		J	V	81	A	$ 17.5266	11,033	D	
COMMON STOCK								1,800	D (1)	

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

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SEC 1474 (9-02)

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

1. Title of Derivative Security (Instr. 3)	2. Conversion or Exercise Price of Derivative Security	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any (Month/Day/Year)	4. Transaction Code (Instr. 8)		5. Number of Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)		6. Date Exercisable and Expiration Date (Month/Day/Year)		7. Title and Amount of Underlying Securities (Instr. 3 and 4)		8. Price of Derivative Security (Instr. 5)	9. Nu Deriv Secur Bene Owne Follo Repo Trans (Instr
				Code	V	(A)	(D)	Date Exercisable	Expiration Date	Title	Amount or Number of Shares		

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
Skillman Rebecca S ONE MAIN ST EVANSVILLE, IN 47708	X			

Signatures

JEFFREY L KNIGHT, EXECUTIVE VICE PRESIDENT AND GENERAL COUNSEL, AS ATTORNEY-IN-FACT	07/11/2017
**Signature of Reporting Person	Date

Explanation of Responses:

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

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

(1) HELD WITH A BROKER

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(1)

7

Inventory

(1)

2

Accounts payable

7

9

Revenue payable

Explanation of Responses:

5

(57)

Other current liabilities

(8)

(95)

Net cash provided by operating activities

1,185

1,019

CASH FLOWS FROM INVESTING ACTIVITIES:

Capital expenditures on oil and natural gas properties		
	(1,958)	
	(927)	
Additions to property, equipment and other assets		
	(34)	
	(20)	
Proceeds from the disposition of assets		

	803
	296
Direct transaction costs for disposition of assets	
	(18)
	-
Funds held in escrow	
	-
	(81)
Contributions to equity method investments	
	-

(51)

Net cash used in investing activities

(1,207)

(783)

CASH FLOWS FROM FINANCING ACTIVITIES:

Proceeds from issuance of debt

2,267

	-
Payments of debt	
	(2,255)
	(600)
Debt extinguishment costs	
	(63)
	(21)
Excess tax deficiency from stock-based compensation (Note 2)	
	-

	(1)
Net proceeds from issuance of common stock	
	-
	1,327
Payments for loan costs	
	(25)
	-
Purchase of treasury stock	
	(23)
	(11)

Explanation of Responses:

Increase in bank overdrafts	68
	-
Net cash provided by (used in) financing activities	(31)
	694
Net increase (decrease) in cash and cash equivalents	(53)

930

Cash and cash equivalents at beginning of period

53

229

Cash and cash equivalents at end of period

$

-

$

1,159

NON-CASH INVESTING AND FINANCING ACTIVITIES:

Issuance of common stock for business combinations

Explanation of Responses:

$	291
$	231

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

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2017

Unaudited

Note 1. *Organization and nature of operations*

Concho Resources Inc. (the "Company") is a Delaware corporation formed on February 22, 2006. The Company's principal business is the acquisition, development, exploration and production of oil and natural gas properties primarily located in the Permian Basin of southeast New Mexico and west Texas.

Note 2. *Summary of significant accounting policies*

Principles of consolidation. The consolidated financial statements of the Company include the accounts of the Company and its 100 percent owned subsidiaries. The Company consolidates the financial statements of these entities. The consolidated financial statements also include the accounts of a variable interest entity ("VIE") where the Company is the primary beneficiary of the arrangements. See Note 4 for additional information regarding the circumstances surrounding the VIE. All material intercompany balances and transactions have been eliminated.

Reclassifications. Certain prior period amounts have been reclassified to conform to the 2017 presentation. These reclassifications had no impact on net income (loss), total stockholders' equity or total cash flows.

Use of estimates in the preparation of financial statements. Preparation of financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from these estimates. Depletion of oil and natural gas properties is determined using estimates of proved oil 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, commodity price outlooks and prevailing market rates of other sources of income and costs. Other significant estimates include, but are not limited to, asset retirement obligations, fair value of stock-based compensation, fair value of business combinations, fair value of nonmonetary exchanges, fair value of derivative financial instruments and income taxes.

Interim financial statements. The accompanying consolidated financial statements of the Company have not been audited by the Company's independent registered public accounting firm, except that the consolidated balance sheet at December 31, 2016 is derived from audited consolidated financial statements. In the opinion of management, the accompanying consolidated financial statements reflect all adjustments necessary to present fairly the Company's consolidated financial statements. All such adjustments are of a normal, recurring nature. In preparing the accompanying consolidated financial statements, management has made certain estimates and assumptions that affect reported amounts in the consolidated financial statements and disclosures of contingencies. Actual results may differ from those estimates. The results for interim periods are not necessarily indicative of annual results.

Certain disclosures have been condensed in or omitted from these consolidated financial statements. Accordingly, these condensed notes to the consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes included in the Company's Annual Report on Form 10-K for the year ended December 31, 2016.

Cash equivalents. The Company considers all cash on hand, depository accounts held by banks, money market accounts and investments with an original maturity of three months or less to be cash equivalents. The Company's cash and cash equivalents are held in financial institutions in amounts that exceed the insurance limits of the Federal Deposit Insurance Corporation. However, management believes that the Company's counterparty risks are minimal based on the reputation and history of the institutions selected. At December 31, 2016, the majority of the Company's cash was invested in stable value government money market funds.

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2017

Unaudited

Equity method investments. At December 31, 2016, the Company owned a 50 percent membership interest in a midstream joint venture, Alpha Crude Connector, LLC ("ACC"), that operated a crude oil gathering and transportation system in the Northern Delaware Basin. In February 2017, the Company closed on the divestiture of its ownership interest in ACC. See Note 4 for additional information regarding the disposition of ACC.

The Company accounted for its investment in ACC under the equity method of accounting for investments in unconsolidated affiliates. The Company's net investment in ACC was approximately $129 million at December 31, 2016, and was included in other assets in the Company's consolidated balance sheet. Gains and losses incurred from the Company's equity investment in ACC were recorded in other income (expense) in its consolidated statements of operations.

The Company owns a 23.75 percent membership interest in Oryx Southern Delaware Holdings, LLC ("Oryx"), an entity that operates a crude oil gathering and transportation system in the Southern Delaware Basin. The Company accounts for its investment in Oryx under the equity method of accounting for investments in unconsolidated affiliates. The Company's net investment in Oryx was approximately $47 million and $42 million at September 30, 2017 and December 31, 2016, respectively, and is included in other assets in the Company's consolidated balance sheets. Gains and losses incurred from the Company's equity investment in Oryx are recorded in other income (expense) in its consolidated statements of operations.

Revenue recognition. Oil and natural gas revenues are recorded at the time of physical transfer of such products to the purchaser, which for the Company is primarily at the wellhead. The Company follows the sales method of accounting for oil and natural gas sales, recognizing revenues based on the Company's actual proceeds from the oil and natural gas sold to purchasers.

General and administrative expense. The Company receives fees for the operation of jointly-owned oil and natural gas properties during the drilling and production phases and records such reimbursements as reductions of general and administrative expense. The Company earned reimbursements of approximately $4 million for each of the three months ended September 30, 2017 and 2016 and approximately $12 million for each of the nine months ended September 30, 2017 and 2016.

Recently adopted accounting pronouncements. The Company adopted Accounting Standards Update ("ASU") No. 2016-09, "Compensation–Stock Compensations (Topic 718): Improvements to Employee Share-based Payment Accounting," on January 1, 2017. The adoption did not have an impact on prior period consolidated financial statements. The Company elected to account for forfeitures of share-based payments as they occur. At December 31, 2016, the Company had not recorded compensation expense of approximately $8 million based on forecasted forfeitures nor the associated deferred tax benefit of approximately $3 million. The Company recognized all excess tax benefits not previously recorded, which totaled approximately $5 million at December 31, 2016. Upon adoption, the Company recorded a cumulative-effect adjustment, which decreased retained earnings by less than $1 million, increased additional paid-in capital by approximately $8 million, and decreased net deferred income taxes by approximately $8 million. The Company elected to prospectively classify excess tax benefits and deficiencies as operating activities on the consolidated statements of cash flows and will prospectively record those excess tax benefits and deficiencies as discrete items in the income tax provision in the consolidated statements of operations. Under the new standard, for the nine months ended September 30, 2017, the Company recorded excess tax benefits of approximately $6 million as offsets to the Company's income tax provision. Also under the new standard, for the three and nine months ended September 30, 2017, the Company recorded forfeitures of share-based payments of approximately $1 million and $7 million, respectively.

New accounting pronouncements issued but not yet adopted. In May 2014, the Financial Accounting Standards Board (the "FASB") issued ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)," which outlines a new, single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized. The new model will require revenue

6

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2017

Unaudited

recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services.

In August 2015, the FASB issued ASU No. 2015-14, “Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date,” which deferred the effective date of ASU No. 2014-09 by one year. That new standard is now effective for annual reporting periods beginning after December 15, 2017. The Company expects to use the modified retrospective method to adopt the standard, meaning the cumulative effect of initially applying the standard will be recognized with an adjustment to retained earnings on January 1, 2018. The Company has substantially completed its internal evaluation of the adoption of this standard, which included a review of all revenue-related contracts with customers and the application of the new revenue recognition model against those contracts. The Company is also updating its revenue recognition policy to conform to the new standard. The Company also expects to expand its revenue recognition related disclosure. Including those changes previously discussed, the Company does not expect this new guidance will have a material impact on its consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02, “Leases (Topic 842),” which supersedes current lease guidance. The new lease standard requires all leases with a term greater than one year to be recognized on the balance sheet while maintaining substantially similar classifications for financing and operating leases. Lease expense recognition on the consolidated statements of operations will be effectively unchanged. This guidance is effective for reporting periods beginning after December 15, 2018, and early adoption is permitted. The Company does not plan to early adopt the standard. The Company enters into lease agreements to support its operations. These agreements are for leases on assets such as office space, vehicles, field services, well equipment and drilling rigs. The Company is currently in the process of reviewing all contracts that could be applicable to this new guidance. The Company believes this new guidance will have a moderate impact to its consolidated balance sheets due to the recognition of right-of-use assets and lease liabilities that are not currently recognized under currently applicable guidance.

In June 2016, the FASB issued ASU No. 2016-13, “Financial Instruments–Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments,” which replaces the current “incurred loss” methodology for recognizing credit losses with an “expected loss” methodology. This new methodology requires that a financial asset measured at amortized cost be presented at the net amount expected to be collected. This standard is intended to provide more timely decision-useful information about the expected credit losses on financial instruments. This guidance is effective for fiscal years beginning after December 15, 2019, and early adoption is allowed as early as fiscal years beginning after December 15, 2018. The Company does not believe this new guidance will have a material impact on its consolidated financial statements.

In January 2017, the FASB issued ASU No. 2017-01, “Business Combinations (Topic 805): Clarifying the Definition of a Business,” with the objective of adding guidance to assist in evaluating whether transactions should be accounted for as asset acquisitions or as business combinations. The guidance provides a screen to determine when an integrated set of assets and activities is not a business. The screen requires that when substantially all of the fair value of the acquired assets is concentrated in a single asset or a group of similar assets, the set is not a business. If the screen is not met, to be considered a business, the set must include an input and a substantive process that together significantly contribute to the ability to create output. This new guidance is effective for annual periods beginning after December 15, 2017, and early adoption is allowed. The Company is evaluating the impact this new guidance will have on its consolidated financial statements.

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2017

Unaudited

Note 3. ***Exploratory well costs***

The Company capitalizes exploratory well costs until a determination is made that the well has either found proved reserves or that it is impaired. After an exploratory well has been completed and found oil and natural gas reserves, a determination may be pending as to whether the oil and natural gas reserves can be classified as proved. In those circumstances, the Company continues to capitalize the well or project costs pending the determination of proved status if (i) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (ii) the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. The capitalized exploratory well costs are carried in unproved oil and natural gas properties. See Note 15 for the proved and unproved components of oil and natural gas properties. If the exploratory well is determined to be impaired, the well costs are charged to exploration and abandonments expense in the consolidated statements of operations.

The following table reflects the Company's net capitalized exploratory well activity during the nine months ended September 30, 2017:

(in millions)		**Nine Months Ended September 30, 2017**
Beginning capitalized exploratory well costs	$	151
Additions to exploratory well costs pending the determination of proved reserves		255
Reclassifications due to determination of proved reserves		(136)
Ending capitalized exploratory well costs	$	270

The following table provides an aging at September 30, 2017 and December 31, 2016 of capitalized exploratory well costs based on the date drilling was completed:

(in millions, except number of projects)	**September 30, 2017**	**December 31, 2016**
Capitalized exploratory well costs that have been capitalized for a period of one year or less	$ 266	$ 141
Capitalized exploratory well costs that have been capitalized for a period greater than one year	4	10
Total capitalized exploratory well costs	$ 270	$ 151
Number of projects with exploratory well costs that have been capitalized for a period greater than one year	4	8

8

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2017

Unaudited

Note 4. ***Acquisitions and divestitures***

Midland Basin acquisition. In July 2017, the Company completed an acquisition in the Midland Basin. As consideration for the acquisition, the Company paid approximately $595 million in cash. The acquisition is subject to customary post-closing adjustments.

Concurrent with the acquisition, the Company entered into a transaction structured as a reverse like-kind exchange ("Reverse 1031 Exchange") in accordance with Section 1031 of the Internal Revenue Code of 1986, as amended (the "Code"). In connection with the Reverse 1031 Exchange, the Company assigned the ownership of the oil and natural gas properties acquired to a VIE formed by an exchange accommodation titleholder. The Company operates the properties pursuant to a management agreement with the VIE. At September 30, 2017, the Company was determined to be the primary beneficiary of the VIE, as the Company had the ability to control the activities that most significantly impact the VIE's economic performance. The assets currently held by the VIE attributable to the acquisition will be conveyed to the Company or one of its subsidiaries, and the VIE structure will terminate, upon the earlier of (i) the completion of the Reverse 1031 Exchange or (ii) the expiration of the time allowed by the treasury regulations and published Internal Revenue Service guidance to complete the Reverse 1031 Exchange, which is 180 days from commencement. At September 30, 2017, the VIE's total assets and liabilities included in the Company's consolidated balance sheet were approximately $607 million and $605 million, respectively.

Northern Delaware Basin acquisition. In April 2017, the Company closed on the remainder of its acquisition in the Northern Delaware Basin. As consideration for the entire acquisition, the Company paid approximately $160 million in cash, of which $43 million was held in escrow at December 31, 2016, and issued to the seller approximately 2.2 million shares of its common stock with an approximate value of $291 million.

ACC divestiture. In February 2017, the Company closed on the divestiture of its ownership interest in ACC. The Company and its joint venture partner entered into separate agreements to sell 100 percent of their respective ownership interests in ACC. After adjustments for debt and working capital, the Company received cash proceeds from the sale of approximately $801 million. After direct transaction costs, the Company recorded a pre-tax gain on disposition of assets of approximately $655 million. The Company's net investment in ACC at the time of closing was approximately $129 million.

Explanation of Responses:

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2017

Unaudited

Note 5. ***Stock incentive plan***

The Company's 2015 Stock Incentive Plan provides for granting stock options, restricted stock awards and performance awards to directors, officers and employees of the Company. The restricted stock-based compensation awards generally vest over a period ranging from one to eight years.

A summary of the Company's Stock Incentive Plan activity for the nine months ended September 30, 2017 is presented below:

	Restricted Stock Shares	Stock Options	Performance Units
Outstanding at December 31, 2016	1,157,270	20,000	331,526
Awards granted (a)	445,384	-	108,398
Options exercised	-	(20,000)	-
Awards cancelled / forfeited	(82,200)	-	(43,333)
Lapse of restrictions	(389,965)	-	-
Outstanding at September 30, 2017	1,130,489	-	396,591
(a) Weighted average grant date fair value per share/unit	$ 121.77	$ -	$ 183.48

The following table reflects the future stock-based compensation expense to be recorded for all the stock-based compensation awards that were outstanding at September 30, 2017:

(in millions)	
Remaining 2017	$ 17
2018	47

2019		25
Thereafter		8
Total	$	97

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2017

Unaudited

Note 6. ***Disclosures about fair value measurements***

The Company uses a valuation framework based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources, whereas unobservable inputs reflect a company's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. These two types of inputs are further prioritized into the following fair value input hierarchy:

Level 1**:** Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. The Company considers active markets to be those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2**:** Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that the Company values using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace. Level 2 instruments primarily include non-exchange traded derivatives such as over-the-counter commodity price swaps, basis swaps, collars and floors, investments and interest rate swaps. The Company's valuation models are primarily industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value, (iii) current market and contractual prices for the underlying instruments and (iv) volatility factors, as well as other relevant economic measures.

Level 3**:** Prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (*i.e.*, supported by little or no market activity). The Company's valuation models are primarily industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value, (iii) volatility factors and (iv) current market and contractual prices for the underlying instruments, as well as other relevant economic measures.

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2017

Unaudited

Financial Assets and Liabilities Measured at Fair Value

The following table presents the carrying amounts and fair values of the Company's financial instruments at September 30, 2017 and December 31, 2016:

(in millions)	September 30, 2017 Carrying Value	September 30, 2017 Fair Value	December 31, 2016 Carrying Value	December 31, 2016 Fair Value
Assets:				
Derivative instruments	$ 32	$ 32	$ 4	$ 4
Liabilities:				
Derivative instruments	$ 43	$ 43	$ 178	$ 178
Credit facility	$ 368	$ 368	$ -	$ -
$600 million 5.5% senior notes due 2022 (a)	$ -	$ -	$ 594	$ 620
$1,550 million 5.5% senior notes due 2023 (a)	$ -	$ -	$ 1,555	$ 1,621
$600 million 4.375% senior notes due 2025 (a)	$ 593	$ 632	$ 592	$ 599
$1,000 million 3.75% senior notes due 2027 (a)	$ 988	$ 1,006	$ -	$ -
$800 million 4.875% senior notes due 2047 (a)	$ 789	$ 834	$ -	$ -

(a) The carrying value includes associated deferred loan costs and any premium (discount).

Credit facility. The carrying amount of the Company's credit facility approximates its fair value, as the applicable interest rates are variable and reflective of market rates.

Senior notes. The fair values of the Company's senior notes are based on quoted market prices. The debt securities are not actively traded and, therefore, are classified as Level 2 in the fair value hierarchy.

Other financial assets and liabilities**.** The Company has other financial instruments consisting primarily of receivables, payables and other current assets and liabilities. The carrying amounts approximate fair value due to the short maturity of these instruments.

Derivative instruments. The fair value of the Company's derivative instruments is estimated by management considering various factors, including closing exchange and over-the-counter quotations and the time value of the underlying commitments. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The following tables summarize (i) the valuation of each of the Company's financial instruments by required fair value hierarchy levels and (ii) the gross fair value by the appropriate balance sheet classification, even when the derivative instruments are subject to netting arrangements and qualify for net presentation in the Company's consolidated balance sheets at September 30, 2017 and December 31, 2016. The Company nets the fair value of derivative instruments by counterparty in the Company's consolidated balance sheets.

	September 30, 2017 Fair Value Measurements Using					Net
(in millions)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value	Gross Amounts Offset in the Consolidated Balance Sheet	Fair Value Presented in the Consolidated Balance Sheet
Assets:						
Current:						
Commodity derivatives	$ -	$ 35	$ -	$ 35	$ (31)	$ 4
Noncurrent:						
Commodity derivatives	-	44	-	44	(16)	28
Liabilities:						
Current:						
Commodity derivatives	-	(68)	-	(68)	31	(37)
Noncurrent:						
Commodity derivatives	-	(22)	-	(22)	16	(6)
Net derivative instruments	$ -	$ (11)	$ -	$ (11)	$ -	$ (11)

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2017

Unaudited

	December 31, 2016					
	Fair Value Measurements Using					Net
(in millions)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value	Gross Amounts Offset in the Consolidated Balance Sheet	Fair Value Presented in the Consolidated Balance Sheet
Assets:						
Current:						
Commodity derivatives	$ -	$ 59	$ -	$ 59	$ (55)	$ 4
Noncurrent:						
Commodity derivatives	-	-	-	-	-	-
Liabilities:						
Current:						
Commodity derivatives	-	(137)	-	(137)	55	(82)
Noncurrent:						
Commodity derivatives	-	(96)	-	(96)	-	(96)
Net derivative instruments	$ -	$ (174)	$ -	$ (174)	$ -	$ (174)

Concentrations of credit risk. At September 30, 2017, the Company’s primary concentrations of credit risk are the risk of collecting accounts receivable and the risk of counterparties’ failure to perform under derivative obligations.

The Company has entered into International Swap Dealers Association Master Agreements (“ISDA Agreements”) with each of its derivative counterparties. The terms of the ISDA Agreements provide the Company and the counterparties with rights of set-off upon the occurrence of defined acts of default by either the Company or a counterparty to a derivative, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party. See Note 7 for additional information regarding the Company’s derivative activities and counterparties.

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2017

Unaudited

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are reported at fair value on a nonrecurring basis in the Company's consolidated balance sheets. The following methods and assumptions were used to estimate the fair values:

Impairments of long-lived assets – The Company periodically reviews its long-lived assets to be held and used, including proved oil and natural gas properties and their integrated assets, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable, for instance when there are declines in commodity prices or well performance. The Company reviews its oil and natural gas properties by depletion base. An impairment loss is indicated if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. If the estimated undiscounted future net cash flows are less than the carrying amount of the Company's assets, it recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset.

The Company calculates the expected undiscounted future net cash flows of its long-lived assets and their integrated assets using management's assumptions and expectations of (i) commodity prices, which are based on the New York Mercantile Exchange ("NYMEX") strip, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) production volumes, (vi) estimated proved reserves and risk-adjusted probable and possible reserves, and (vii) prevailing market rates of income and expenses from integrated assets. At September 30, 2017, the Company's estimates of commodity prices for purposes of determining undiscounted future cash flows, which are based on the NYMEX strip, ranged from a 2017 price of $52.29 per barrel of oil decreasing to a 2021 price of $50.77 per barrel of oil partially recovering to a 2024 price of $52.01 per barrel of oil. Similarly, natural gas prices ranged from a 2017 price of $3.14 per Mcf of natural gas decreasing to a 2020 price of $2.85 per Mcf of natural gas partially recovering to a 2024 price of $2.88 per Mcf of natural gas. Commodity prices for this purpose were held flat after 2024.

The Company calculates the estimated fair values of its long-lived assets and their integrated assets using a discounted future cash flow model. Fair value assumptions associated with the calculation of discounted future net cash flows include (i) market estimates of commodity prices, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) production volumes, (vi) estimated proved reserves and risk-adjusted probable and possible reserves, (vii) prevailing market rates of income and expenses from integrated assets and (viii) a discount rate. The expected future net cash flows were discounted using an annual rate of 10 percent to determine fair value. These are classified as Level 3 fair value assumptions.

During the three months ended March 31, 2016, NYMEX strip prices declined as compared to December 31, 2015, and as a result the carrying amount of the Company's Yeso field of approximately $3.4 billion exceeded the expected undiscounted future net cash flows resulting in a non-cash charge against earnings of approximately $1.5 billion. The non-cash charge represented the amount by which the carrying amount exceeded the estimated fair value of the assets.

The following table reports the carrying amount, estimated fair value and impairment expense of long-lived assets for the indicated period:

(in millions)	**Carrying Amount**	**Estimated Fair Value (Level 3)**	**Impairment Expense**
March 2016	$ 3,438	$ 1,913	$ 1,525

It is reasonably possible that the estimate of undiscounted future net cash flows of the Company's long-lived assets may change in the future resulting in the need to impair carrying values. The primary factors that may affect estimates of future cash flows are (i) commodity prices including differentials, (ii) increases or decreases in production and capital costs, (iii)

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2017

Unaudited

future reserve volume adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves, (iv) results of future drilling activities and (v) changes in income and expenses from integrated assets.

Note 7. ***Derivative financial instruments***

The Company uses derivative financial instruments to manage its exposure to commodity price fluctuations. Commodity derivative instruments are used to (i) reduce the effect of the volatility of price changes on the oil and natural gas the Company produces and sells, (ii) support the Company’s capital budget and expenditure plans and (iii) support the economics associated with acquisitions. The Company does not enter into derivative financial instruments for speculative or trading purposes. The Company also enters into fixed-price forward physical power purchase contracts to manage the volatility of the price of power needed for ongoing operations. The Company may also enter into physical delivery contracts to effectively provide commodity price hedges. Because these physical contracts are not expected to be net cash settled, the Company has elected normal purchase or normal sale treatment and are thus recorded at cost.

The Company does not designate its derivative instruments to qualify for hedge accounting. Accordingly, the Company reflects changes in the fair value of its derivative instruments in its consolidated statements of operations as they occur.

The following table summarizes the amounts reported in earnings related to the commodity derivative instruments for the three and nine months ended September 30, 2017 and 2016:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	**2017**	**2016**	**2017**	**2016**
Gain (loss) on derivatives:				
Oil derivatives	$ (205)	$ 36	$ 260	$ (173)

Natural gas derivatives		(1)		5		29		(3)
Total	$	(206)	$	41	$	289	$	(176)

The following table represents the Company’s net cash receipts from (payments on) derivatives for the three and nine months ended September 30, 2017 and 2016:

	Three Months Ended September 30,				Nine Months Ended September 30,			
(in millions)		**2017**		**2016**		**2017**		**2016**
Net cash receipts from (payments on) derivatives:								
Oil derivatives	$	28	$	154	$	129	$	566
Natural gas derivatives		2		1		(3)		16
Total	$	30	$	155	$	126	$	582

16

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2017

Unaudited

Commodity derivative contracts at September 30, 2017. The following table sets forth the Company's outstanding derivative contracts at September 30, 2017. When aggregating multiple contracts, the weighted average contract price is disclosed. All of the Company's derivative contracts at September 30, 2017 are expected to settle by December 31, 2019.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Price Swaps: (a)					
2017:					
Volume (Bbl)				9,370,080	9,370,080
Price per Bbl				$ 51.33	$ 51.33
2018:					
Volume (Bbl)	8,180,629	7,546,170	7,064,318	6,676,007	29,467,124
Price per Bbl	$ 51.54	$ 51.45	$ 51.36	$ 51.26	$ 51.41
2019:					
Volume (Bbl)	5,314,000	5,090,000	4,897,000	4,721,000	20,022,000
Price per Bbl	$ 52.54	$ 52.52	$ 52.54	$ 52.55	$ 52.54
Oil Basis Swaps: (b)					
2017:					
Volume (Bbl)				8,508,000	8,508,000
Price per Bbl				$ (0.74)	$ (0.74)
2018:					
Volume (Bbl)	7,936,000	7,521,000	6,961,000	6,684,000	29,102,000
Price per Bbl	$ (1.02)	$ (1.01)	$ (1.01)	$ (1.01)	$ (1.01)
2019:					
Volume (Bbl)	4,581,000	4,428,000	4,262,000	4,139,000	17,410,000
Price per Bbl	$ (1.17)	$ (1.17)	$ (1.18)	$ (1.18)	$ (1.17)
Natural Gas Price Swaps: (c)					
2017:					
Volume (MMBtu)				14,673,000	14,673,000
Price per MMBtu				$ 3.10	$ 3.10
2018:					
Volume (MMBtu)	11,156,000	10,641,000	10,219,000	9,904,000	41,920,000
Price per MMBtu	$ 3.06	$ 3.05	$ 3.05	$ 3.04	$ 3.05
2019:					
Volume (MMBtu)	2,791,533	2,681,387	2,578,537	2,489,535	10,540,992
Price per MMBtu	$ 2.86	$ 2.85	$ 2.85	$ 2.85	$ 2.85

(a) The index prices for the oil price swaps are based on the NYMEX – West Texas Intermediate ("WTI") monthly average futures price.
(b) The basis differential price is between Midland – WTI and Cushing – WTI.
(c) The index prices for the natural gas price swaps are based on the NYMEX – Henry Hub last trading day futures price.

Derivative counterparties. The Company uses credit and other financial criteria to evaluate the creditworthiness of counterparties to its derivative instruments. The Company believes that all of its derivative counterparties are currently acceptable credit risks. The Company is not required to provide credit support or collateral to any counterparties under its derivative contracts, nor are they required to provide credit support to the Company. In September 2017, the Company elected to enter into an "Investment Grade Period" under the Credit Facility, as defined below, which had the effect of releasing all collateral formerly securing the Credit Facility. Additionally, as a result of the Company's Investment Grade Period election along with amendments to certain ISDA Agreements with the Company's derivative counterparties, the Company's derivatives are no longer secured. See Note 8 for additional information regarding the Credit Facility.

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2017

Unaudited

Note 8. ***Debt***

The Company's debt consisted of the following at September 30, 2017 and December 31, 2016:

(in millions)		**September 30, 2017**		**December 31, 2016**
Credit facility	$	368	$	-
5.5% unsecured senior notes due 2022		-		600
5.5% unsecured senior notes due 2023		-		1,550
4.375% unsecured senior notes due 2025		600		600
3.75% unsecured senior notes due 2027		1,000		-
4.875% unsecured senior notes due 2047		800		-
Unamortized original issue premium (discount), net		(6)		22
Senior notes issuance costs, net		(24)		(31)
Less: current portion		-		-
Total long-term debt	$	2,738	$	2,741

Credit facility. The Company's credit facility, as amended and restated (the "Credit Facility"), has a maturity date of May 9, 2022. At September 30, 2017, the Company's commitments from its bank group were $2.0 billion.

In April 2017, the Company amended the Credit Facility to extend the maturity date, increase the borrowing base and decrease unused lender commitments. The amendment also lowered the corporate ratings floor sufficient to automatically terminate an Investment Grade Period under the Credit Facility from (i) "Ba1" to "Ba2" for Moody's Investors Service, Inc. ("Moody's") and (ii) "BB+" to "BB" for S&P Global Ratings ("S&P").

The Company recorded a loss on extinguishment of debt of approximately $1 million during the nine months ended September 30, 2017 for the proportional amount of unamortized deferred loan costs associated with banks that are no longer in the Credit Facility syndicate as a result of the April 2017 amendment.

In September 2017, the Company elected to enter into an Investment Grade Period under the Credit Facility, which had the effect of releasing all collateral formerly securing the Credit Facility. If the Investment Grade Period under the Credit Facility terminates (whether automatically due to a downgrade of the Company's credit ratings below certain thresholds or by the Company's election), the Credit Facility will once again be secured by a first lien on substantially all of the Company's oil and natural gas properties and by a pledge of the equity interests in its subsidiaries. At September 30, 2017, certain of the Company's 100 percent owned subsidiaries are guarantors under the Credit Facility.

During an Investment Grade Period, advances on the Credit Facility bear interest, at the Company's option, based on (i) an alternative base rate, which is equal to the highest of (a) the prime rate of JPMorgan Chase Bank (4.25 percent at September 30, 2017), (b) the federal funds effective rate plus 0.5 percent and (c) the London Interbank Offered Rate ("LIBOR") plus 1.0 percent or (ii) LIBOR. The Credit Facility's interest rates and commitment fees on the unused portion of the available commitment vary depending on the Company's credit ratings from Moody's and S&P. At the Company's current credit ratings, LIBOR Rate Loans and Alternate Base Rate Loans bear interest margins of 150 basis points and 50 basis points per annum, respectively, and commitment fees on the unused portion of the available commitment are 25 basis points per annum.

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2017

Unaudited

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

- maintenance of certain financial ratios, including maintenance of a quarterly ratio of consolidated total debt to consolidated earnings before interest expense, income taxes, depletion, depreciation, and amortization, exploration expense and other noncash income and expenses to be no greater than 4.25 to 1.0, and during an Investment Grade Period, if the Company does not have both a rating of "Baa3" or better from Moody's and a rating of "BBB-" or better from S&P, maintenance of a quarterly ratio of PV-9 of the Company's oil and natural gas properties reflected in its most recently delivered reserve report to consolidated total debt to be no less than 1.50 to 1.0;

- limits on the incurrence of additional indebtedness and certain types of liens;

- restrictions as to mergers, combinations and dispositions of assets; and

- restrictions on the payment of cash dividends.

Senior notes. Interest on the Company's senior notes is paid in arrears semi-annually. The senior notes are fully and unconditionally guaranteed on a senior unsecured basis by certain of the Company's 100 percent owned subsidiaries, subject to customary release provisions as described in Note 13.

In September 2017, the Company issued $1,800 million in aggregate principal amount of unsecured senior notes, consisting of $1,000 million in aggregate principal amount of 3.75% unsecured senior notes due 2027 (the "3.75% Notes") and $800 million in aggregate principal amount of 4.875% unsecured senior notes due 2047 (the "4.875% Notes" and, together with the 3.75% Notes, the "Notes"). The 3.75% Notes were issued at a price equal to 99.636 percent of par, and the 4.875% Notes were issued at a price equal to 99.749 percent of par. The Company received net proceeds of approximately $1,777 million.

Additionally, in September 2017, the Company completed a cash tender offer (the “Tender Offer”) to purchase any and all of the outstanding $600 million aggregate principal amount of its 5.5% unsecured senior notes due 2022 and the outstanding $1,550 million aggregate principal amount of its 5.5% unsecured senior notes due 2023 (collectively, the “5.5% Notes”). The Company received tenders from the holders of approximately $1,232 million in aggregate principal amount, or approximately 57.3 percent, of its outstanding 5.5% Notes in connection with the Tender Offer at a price of 102.934 percent of the unpaid principal amount plus accrued and unpaid interest to the settlement date.

In connection with the Tender Offer, the Company redeemed the remaining outstanding 5.5% Notes not purchased in the Tender Offer at a price, including the make-whole premium as determined in accordance with the indentures, of 102.75 percent of the unpaid principal amount plus accrued and unpaid interest. Additionally in September 2017, the Company completed a satisfaction and discharge of the redeemed notes, where the Company prepaid interest to October 13, 2017. The Company used the net proceeds from the offering of the Notes, together with cash on hand and borrowings under its Credit Facility, to fund the Tender Offer and the satisfaction and discharge of its obligations under the indentures of the 5.5% Notes.

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2017

Unaudited

As a result of these transactions, the Company recorded a loss on extinguishment of debt for the three and nine months ended September 30, 2017 as follows:

(in millions)	**Tender Offer**	**Extinguishment**	**Total**
Tender premium	$ 36	$ -	$ 36
Make-whole premium	-	25	25
Prepaid interest	-	2	2
Unamortized original issue premium	(11)	(8)	(19)
Unamortized deferred loan costs	12	9	21
Total loss on extinguishment of debt	$ 37	$ 28	$ 65

At September 30, 2017, the Company was in compliance with the covenants under all of its debt instruments.

Principal maturities of long-term debt. Principal maturities of long-term debt outstanding at September 30, 2017 were as follows:

(in millions)	
Remaining 2017	$ -
2018	-
2019	-
2020	-
2021	-
2022	368
Thereafter	2,400
Total	$ 2,768

Interest expense. The following amounts have been incurred and charged to interest expense for the three and nine months ended September 30, 2017 and 2016:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	**2017**	**2016**	**2017**	**2016**
Cash payments for interest	$ 73	$ 109	$ 138	$ 215
Non-cash interest	1	3	5	7
Net changes in accruals	(35)	(59)	(25)	(60)
Total interest expense	$ 39	$ 53	$ 118	$ 162

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2017

Unaudited

Note 9. ***Commitments and contingencies***

Legal actions. The Company is a 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 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.

Severance tax, royalty and joint interest audits. The Company is subject to routine severance, royalty and joint interest audits from regulatory bodies and non-operators and makes accruals as necessary for estimated exposure when deemed probable and estimable. Additionally, the Company is subject to various possible contingencies that arise primarily from interpretations affecting the oil and natural gas industry. Such contingencies include differing interpretations as to the prices at which oil and natural gas sales may be made, the prices at which royalty owners may be paid for production from their leases, allowable costs under joint interest arrangements and other matters. At December 31, 2016, the Company had $7 million accrued for estimated exposure that has since been satisfied. Although the Company believes that it has estimated its exposure with respect to the various laws and regulations, administrative rulings and interpretations thereof, adjustments could be required as new interpretations and regulations are issued.

Commitments. The Company periodically enters into contractual arrangements under which the Company is committed to expend funds. These contractual arrangements relate to purchase agreements the Company has entered into including drilling commitments, water commitment agreements, throughput volume delivery commitments, power commitments, fixed asset commitments and maintenance commitments. The following table summarizes the Company's commitments at September 30, 2017:

(in millions)		
Remaining 2017	$	10
2018		40

2019		59
2020		32
2021		31
2022		26
Thereafter		88
Total	$	286

21

Operating leases. The Company leases vehicles, equipment and office facilities under non-cancellable operating leases. Lease payments associated with these operating leases were approximately $2 million for each of the three months ended September 30, 2017 and 2016 and approximately $7 million and $6 million for the nine months ended September 30, 2017 and 2016, respectively.

Future minimum lease commitments under non-cancellable operating leases at September 30, 2017 were as follows:

(in millions)		
Remaining 2017	$	2
2018		9
2019		7
2020		6
2021		4
2022		-
Thereafter		1
Total	$	29

Note 10. ***Income taxes***

The effective income tax rates were 36.7 percent and 37.3 percent for the three months ended September 30, 2017 and 2016, respectively, and 36.6 percent and 36.9 percent for the nine months ended September 30, 2017 and 2016, respectively. Total income tax expense for the nine months ended September 30, 2017 differed from amounts computed by applying the United States federal statutory tax rates to pre-tax income primarily due to state income taxes and the impact of permanent differences between book and taxable income. The Company recorded a discrete income tax benefit of approximately $6 million for the nine months ended September 30, 2017 related to excess tax benefits on stock-based awards, which are recorded in the income tax provision pursuant to ASU No. 2016-09, which was adopted on January 1, 2017. Total income tax benefit for the three months ended September 30, 2017 and the three and nine months ended September 30, 2016 differed from amounts computed by applying the United States federal statutory tax rates to pre-tax loss primarily due to state income taxes, partially offset by the impact of permanent differences between book and taxable loss.

Note 11. ***Related party transactions***

The Company paid royalties on certain properties to a partnership in which a director of the Company is the general partner and owns a 3.5 percent partnership interest. These payments were reported in the Company’s consolidated statements of operations and totaled approximately $1 million for each of the three months ended September 30, 2017 and 2016 and approximately $5 million and $3 million for the nine months ended September 30, 2017 and 2016, respectively.

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2017

Unaudited

Note 12. ***Earnings per share***

The Company uses the two-class method of calculating earnings per share because certain of the Company's unvested share-based awards qualify as participating securities.

The Company's basic earnings per share attributable to common stockholders is computed as (i) net income (loss) as reported, (ii) less participating basic earnings (iii) divided by weighted average basic common shares outstanding. The Company's diluted earnings per share attributable to common stockholders is computed as (i) basic earnings attributable to common stockholders, (ii) plus reallocation of participating earnings (iii) divided by weighted average diluted common shares outstanding.

The following table reconciles the Company's earnings from operations and earnings attributable to common stockholders to the basic and diluted earnings used to determine the Company's earnings per share amounts for the three and nine months ended September 30, 2017 and 2016, respectively, under the two-class method:

(in millions)	**Three Months Ended September 30,**				**Nine Months Ended September 30,**			
		2017		**2016**		**2017**		**2016**
Net income (loss) as reported	$	(113)	$	(51)	$	689	$	(1,337)
Participating basic earnings (a)		-		-		(5)		-
Basic earnings attributable to common stockholders		(113)		(51)		684		(1,337)
Reallocation of participating earnings		-		-		-		-
Diluted earnings attributable to common stockholders	$	(113)	$	(51)	$	684	$	(1,337)

(a) Unvested restricted stock awards represent participating securities because they participate in nonforfeitable dividends or distributions with the common equity holders of the Company. Participating earnings represent the distributed earnings of the Company attributable to the participating securities. Unvested restricted stock awards do not participate in undistributed net losses as they are not contractually obligated to do so.

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2017

Unaudited

The following table is a reconciliation of the basic weighted average common shares outstanding to diluted weighted average common shares outstanding for the three and nine months ended September 30, 2017 and 2016:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	**2017**	**2016**	**2017**	**2016**
Weighted average common shares outstanding:				
Basic	147,557	135,454	147,233	131,417
Dilutive common stock options	-	-	4	-
Dilutive performance units	-	-	549	-
Diluted	147,557	135,454	147,786	131,417

The following table is a summary of the performance units that were not included in the computation of diluted earnings per share, as inclusion of these items would be antidilutive:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in thousands)	**2017**	**2016**	**2017**	**2016**
Number of antidilutive units:				
Antidilutive performance units	-	-	107	-

Performance unit awards. The number of shares of common stock that will ultimately be issued for performance units will be determined by a combination of (i) comparing the Company’s total shareholder return relative to the total shareholder return of a predetermined group of peer companies at the end of the performance period and (ii) the Company’s absolute total shareholder return at the end of the performance period. The performance period is 36 months. The actual payout of shares will be between zero and 300 percent.

24

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2017

Unaudited

Note 13. ***Subsidiary guarantors***

At September 30, 2017, certain of the Company's 100 percent owned subsidiaries have fully and unconditionally guaranteed the Company's senior notes. The indentures governing the Company's senior notes provide that the guarantees of its subsidiary guarantors will be released in certain customary circumstances including (i) in connection with any sale, exchange or other disposition, whether by merger, consolidation or otherwise, of the capital stock of that guarantor to a person that is not the Company or a restricted subsidiary of the Company, such that, after giving effect to such transaction, such guarantor would no longer constitute a subsidiary of the Company, (ii) in connection with any sale, exchange or other disposition (other than a lease) of all or substantially all of the assets of that guarantor to a person that is not the Company or a restricted subsidiary of the Company, (iii) upon the merger of a guarantor into the Company or any other guarantor or the liquidation or dissolution of a guarantor, (iv) if the Company designates any restricted subsidiary that is a guarantor to be an unrestricted subsidiary in accordance with the indenture, (v) upon legal defeasance or satisfaction and discharge of the indenture and (vi) upon written notice of such release or discharge by the Company to the trustee following the release or discharge of all guarantees by such guarantor of any indebtedness that resulted in the creation of such guarantee, except a discharge or release by or as a result of payment under such guarantee.

See Note 8 for a summary of the Company's senior notes. In accordance with practices accepted by the United States Securities and Exchange Commission, the Company has prepared condensed consolidating financial statements in order to quantify the assets, results of operations and cash flows of such subsidiaries as subsidiary guarantors. In addition, two of the Company's subsidiaries do not guarantee the Company's senior notes and are included in the Company's consolidated financial statements. One of such entities is a VIE that was formed to effectuate a tax-free exchange of assets, and the other entity is a 100 percent owned subsidiary that was recently acquired. These entities are referred to as "Subsidiary Non-Guarantors" in the tables below.

The following condensed consolidating balance sheets at September 30, 2017 and December 31, 2016, condensed consolidating statements of operations for the three and nine months ended September 30, 2017 and 2016 and condensed consolidating statements of cash flows for the nine months ended September 30, 2017 and 2016, present financial information for Concho Resources Inc. as the parent on a stand-alone basis (carrying any investments in subsidiaries under the equity method), financial information for the subsidiary guarantors on a stand-alone basis (carrying any investment in non-guarantor subsidiaries under the equity method), financial information for the subsidiary non-guarantors on a stand-alone basis and the consolidation and elimination entries necessary to arrive at the information for the Company on a consolidated basis. All current and deferred income taxes are recorded on Concho Resources Inc., as the subsidiaries are flow-through entities for income tax purposes. The subsidiary guarantors and subsidiary non-guarantors are not restricted from making distributions to the Company.

25

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2017

Unaudited

Condensed Consolidating Balance Sheet
September 30, 2017

(in millions)	Parent Issuer	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Entries	Total
ASSETS					
Accounts receivable - related parties	$ 8,903	$ (653)	$ -	$ (8,250)	$ -
Other current assets	14	515	6	-	535
Oil and natural gas properties, net	-	11,968	619	-	12,587
Property and equipment, net	-	232	-	-	232
Investment in subsidiaries	2,963	-	-	(2,963)	-
Other long-term assets	42	86	-	-	128
Total assets	$ 11,922	$ 12,148	$ 625	$ (11,213)	$ 13,482
LIABILITIES AND EQUITY					
Accounts payable - related parties	$ (653)	$ 8,290	$ 613	$ (8,250)	$ -
Other current liabilities	50	756	4	-	810
Long-term debt	2,738	-	-	-	2,738
Other long-term liabilities	1,156	141	6	-	1,303
Equity	8,631	2,961	2	(2,963)	8,631
Total liabilities and equity	$ 11,922	$ 12,148	$ 625	$ (11,213)	$ 13,482

Condensed Consolidating Balance Sheet
December 31, 2016

(in millions)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
ASSETS				
Accounts receivable - related parties	$ 8,991	$ (336)	$ (8,655)	$ -
Other current assets	12	534	-	546
Oil and natural gas properties, net	-	11,086	-	11,086
Property and equipment, net	-	216	-	216
Investment in subsidiaries	1,989	-	(1,989)	-

Other long-term assets		11		260		-		271
Total assets	$	11,003	$	11,760	$	(10,644)	$	12,119
LIABILITIES AND EQUITY								
Accounts payable - related parties	$	(336)	$	8,991	$	(8,655)	$	-
Other current liabilities		114		639		-		753
Long-term debt		2,741		-		-		2,741
Other long-term liabilities		861		141		-		1,002
Equity		7,623		1,989		(1,989)		7,623
Total liabilities and equity	$	11,003	$	11,760	$	(10,644)	$	12,119

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

September 30, 2017

Unaudited

Condensed Consolidating Statement of Operations
Three Months Ended September 30, 2017

(in millions)	Parent Issuer	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Entries	Total
Total operating revenues	$ -	$ 619	$ 8	$ -	$ 627
Total operating costs and expenses	(207)	(491)	(6)	-	(704)
Income (loss) from operations	(207)	128	2	-	(77)
Interest expense	(39)	-	-	-	(39)
Loss on extinguishment of debt	(65)	-	-	-	(65)
Other, net	132	2	-	(132)	2
Income (loss) before income taxes	(179)	130	2	(132)	(179)
Income tax benefit	66	-	-	-	66
Net income (loss)	$ (113)	$ 130	$ 2	$ (132)	$ (113)

Condensed Consolidating Statement of Operations
Three Months Ended September 30, 2016

(in millions)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Total operating revenues	$ -	$ 430	$ -	$ 430
Total operating costs and expenses	41	(469)	-	(428)
Income (loss) from operations	41	(39)	-	2
Interest expense	(52)	(1)	-	(53)
Loss on extinguishment of debt	(28)	-	-	(28)
Other, net	(42)	(2)	42	(2)
Loss before income taxes	(81)	(42)	42	(81)

Income tax benefit		30		-		-		30
Net loss	$	(51)	$	(42)	$	42	$	(51)

Condensed Consolidating Statement of Operations
Nine Months Ended September 30, 2017

(in millions)	Parent Issuer	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Entries	Total
Total operating revenues	$ -	$ 1,798	$ 8	$ -	$ 1,806
Total operating costs and expenses	288	(835)	(6)	-	(553)
Income from operations	288	963	2	-	1,253
Interest expense	(117)	(1)	-	-	(118)
Loss on extinguishment of debt	(66)	-	-	-	(66)
Other, net	982	18	-	(982)	18
Income before income taxes	1,087	980	2	(982)	1,087
Income tax expense	(398)	-	-	-	(398)
Net income	$ 689	$ 980	$ 2	$ (982)	$ 689

Condensed Consolidating Statement of Operations
Nine Months Ended September 30, 2016

(in millions)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Total operating revenues	$ -	$ 1,110	$ -	$ 1,110
Total operating costs and expenses	(177)	(2,853)	-	(3,030)
Loss from operations	(177)	(1,743)	-	(1,920)
Interest expense	(159)	(3)	-	(162)
Loss on extinguishment of debt	(28)	-	-	(28)
Other, net	(1,755)	(10)	1,756	(9)
Loss before income taxes	(2,119)	(1,756)	1,756	(2,119)
Income tax benefit	782	-	-	782
Net loss	$ (1,337)	$ (1,756)	$ 1,756	$ (1,337)

Condensed Consolidating Statement of Cash Flows
Nine Months Ended September 30, 2017

(in millions)	Parent Issuer	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Entries	Total
Net cash flows provided by operating activities	$ 99	$ 1,084	$ 2	$ -	$ 1,185
Net cash flows used in investing activities	-	(592)	(615)	-	(1,207)
Net cash flows provided by (used in) financing activities	(99)	(545)	613	-	(31)
Net decrease in cash and cash equivalents	-	(53)	-	-	(53)
Cash and cash equivalents at beginning of period	-	53	-	-	53
Cash and cash equivalents at end of period	$ -	$ -	$ -	$ -	$ -

Condensed Consolidating Statement of Cash Flows
Nine Months Ended September 30, 2016

(in millions)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Net cash flows provided by (used in) operating activities	$ (694)	$ 1,713	$ -	$ 1,019
Net cash flows used in investing activities	-	(783)	-	(783)
Net cash flows provided by financing activities	694	-	-	694
Net increase in cash and cash equivalents	-	930	-	930
Cash and cash equivalents at beginning of period	-	229	-	229
Cash and cash equivalents at end of period	$ -	$ 1,159	$ -	$ 1,159

Explanation of Responses:

Note 14. ***Subsequent events***

New commodity derivative contracts. After September 30, 2017, the Company entered into the following oil price swaps, oil basis swaps and natural gas price swaps to hedge additional amounts of the Company's estimated future production:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Price Swaps: (a)					
2017:					
Volume (Bbl)				846,000	846,000
Price per Bbl				$ 51.29	$ 51.29
2018:					
Volume (Bbl)	953,000	600,000	407,000	296,000	2,256,000
Price per Bbl	$ 51.55	$ 51.39	$ 51.43	$ 51.28	$ 51.45
2019:					
Volume (Bbl)	1,035,000	1,046,500	828,000	828,000	3,737,500
Price per Bbl	$ 51.25	$ 51.25	$ 51.14	$ 51.14	$ 51.20
Oil Basis Swaps: (b)					
2017:					
Volume (Bbl)				1,499,000	1,499,000
Price per Bbl				$ (0.12)	$ (0.12)
2018:					
Volume (Bbl)	540,000	546,000	276,000	276,000	1,638,000
Price per Bbl	$ (0.21)	$ (0.21)	$ (0.38)	$ (0.38)	$ (0.27)
2019:					
Volume (Bbl)	1,395,000	1,410,500	1,426,000	1,426,000	5,657,500
Price per Bbl	$ (0.68)	$ (0.68)	$ (0.68)	$ (0.68)	$ (0.68)
Natural Gas Price Swaps: (c)					
2017:					
Volume (MMBtu)				3,660,000	3,660,000
Price per MMBtu				$ 3.02	$ 3.02
2018:					
Volume (MMBtu)	5,400,000	5,460,000	4,600,000	4,600,000	20,060,000
Price per MMBtu	$ 3.02	$ 3.02	$ 3.01	$ 3.01	$ 3.02
2019:					
Volume (MMBtu)	1,800,000	1,820,000	1,840,000	1,840,000	7,300,000
Price per MMBtu	$ 2.86	$ 2.86	$ 2.86	$ 2.86	$ 2.86

(a) The index prices for the oil price swaps are based on the NYMEX – WTI monthly average futures price.

(b) The basis differential price is between Midland – WTI and Cushing – WTI.

(c) The index prices for the natural gas price swaps are based on the NYMEX – Henry Hub last trading day futures price.

Note 15. ***Supplementary information***

Capitalized costs

(in millions)		**September 30, 2017**		**December 31, 2016**
Oil and natural gas properties:				
Proved	$	17,950	$	16,620
Unproved		2,804		1,856
Less: accumulated depletion		(8,167)		(7,390)
Net capitalized costs for oil and natural gas properties	$	12,587	$	11,086

Costs incurred for oil and natural gas producing activities

(in millions)	**Three Months Ended September 30,**				**Nine Months Ended September 30,**			
		2017		**2016**		**2017**		**2016**
Property acquisition costs:								
Proved	$	162	$	1	$	301	$	257
Unproved		472		14		865		172
Exploration		252		177		725		513
Development		175		97		478		287
Total costs incurred for oil and natural gas properties	$	1,061	$	289	$	2,369	$	1,229

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

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. This section should be read in conjunction with our historical consolidated financial statements and notes.

Certain statements in our discussion below are forward-looking statements. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause actual results to differ materially from those implied or expressed by the forward-looking statements. Please see "Cautionary Statement Regarding Forward-Looking Statements."

Overview

We are an independent oil and natural gas company engaged in the acquisition, development, exploration and production of oil and natural gas properties. Our core operations are primarily focused in the Permian Basin of southeast New Mexico and west Texas. Concho's legacy in the Permian Basin provides us a deep understanding of operating and geological trends. We are actively applying new technologies, such as extended length lateral drilling, multi-well pad development and enhanced completion techniques, throughout our four core operating areas: the Northern Delaware Basin, the Southern Delaware Basin, the Midland Basin and the New Mexico Shelf. Oil comprised 59 percent of our 720 MMBoe of estimated proved reserves at December 31, 2016 and 62 percent of our 186,449 Boe of average daily production for the nine months ended September 30, 2017. We seek to operate the wells in which we own an interest, and we operated wells that accounted for 92 percent of our proved developed producing reserves and 79 percent of our 7,858 gross wells at December 31, 2016. By controlling operations, we are able to more effectively manage the cost and timing of exploration and development of our properties, including the drilling and stimulation methods used.

Financial and Operating Performance

Our financial and operating performance for the nine months ended September 30, 2017 and 2016 included the following highlights:

- Net income was $689 million ($4.63 per diluted share) as compared to net loss of $1.3 billion ($(10.18) per diluted share) for the first nine months of 2017 and 2016, respectively. The increase was primarily due to:

- no recorded impairments of long-lived assets during the nine months ended September 30, 2017, as compared to $1.5 billion in non-cash impairment charges in 2016, primarily attributable to properties in our New Mexico Shelf area;

- $696 million increase in oil and natural gas revenues as a result of a 28 percent increase in production and a 28 percent increase in commodity price realizations per Boe (excluding the effects of derivative activities);

- gain on disposition of assets, net increased $558 million due to a gain of approximately $667 million during the nine months ended September 30, 2017 primarily due to our disposition of Alpha Crude Connector, LLC (“ACC”), as compared to a gain of approximately $109 million during 2016 primarily attributable to our Northern Delaware Basin divestiture in February 2016;

- $465 million change in (gain) loss on derivatives due to a $289 million gain on derivatives during the nine months ended September 30, 2017, as compared to a $176 million loss on derivatives during 2016; and

- $42 million decrease in depreciation, depletion and amortization expense, primarily due to a decrease in the depletion rate per Boe period over period, partially offset by an increase in production;

partially offset by:

- $1.2 billion change in our income tax provision due to income before income taxes during the nine months ended September 30, 2017, as compared to a loss before income taxes during 2016;

• $53 million increase in production expense, primarily due to increased production associated with our wells successfully drilled and completed in 2016 and 2017; and

• $51 million increase in production and ad valorem tax expense, primarily due to increased production taxes as a result of increased oil and natural gas sales.

• Average daily sales volumes of 186,449 Boe per day during the first nine months of 2017 increased 28 percent as compared to 145,868 Boe per day during 2016.

• Net cash provided by operating activities increased by approximately $166 million to $1,185 million for the first nine months of 2017, as compared to $1,019 million in the first nine months of 2016, primarily due to an increase in oil and natural gas revenues and decreased cash interest expense, partially offset by (i) a decrease in cash settlements on derivatives, (ii) increased production expense, (iii) increased production tax expense and (iv) changes related to cash income taxes.

• Cash decreased by approximately $53 million during the first nine months of 2017 primarily as a result of cash paid to tender and extinguish our 5.5% Notes, as defined below, and cash paid for the Midland Basin and Northern Delaware Basin acquisitions, partially offset by proceeds from the issuance of the Notes, as defined below, and proceeds from our February 2017 divestiture of ACC.

Commodity Prices

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

• continuing economic uncertainty worldwide;

• political and economic developments in oil and natural gas producing regions, including Africa, South America and the Middle East;

- the extent to which members of the Organization of Petroleum Exporting Countries and other oil exporting nations are able to influence global oil supply levels;

- technological advances affecting energy consumption and energy supply;

- domestic and foreign governmental regulations, including limits on the United States' ability to export crude oil, and taxation;

- the level of global inventories;

- the proximity, capacity, cost and availability of pipelines and other transportation facilities, as well as the availability of commodity processing and gathering and refining capacity;

- risks related to the concentration of our operations in the Permian Basin of southeast New Mexico and west Texas and the level of commodity inventory in the Permian Basin;

- the quality of the oil we produce;

- the overall global demand for oil, natural gas and natural gas liquids;

- the domestic and foreign supply of oil, natural gas and natural gas liquids;

- political and economic events that directly or indirectly impact the relative strength or weakness of the United States dollar, on which oil prices are benchmarked globally, against foreign currencies;

- the effect of energy conservation efforts;

- the price and availability of alternative fuels; and

33

Explanation of Responses:

- overall North American oil, natural gas and natural gas liquids supply and demand fundamentals, including:

- the United States economy,

- weather conditions, and

- liquefied natural gas deliveries to and exports from the United States.

Although we cannot predict the occurrence of events that may affect future commodity prices or the degree to which these prices will be affected, the prices for any commodity that we produce will generally approximate current market prices in the geographic region of the production. From time to time, we expect that we may economically hedge a portion of our commodity price risk to mitigate the impact of price volatility on our business. See Notes 7 and 14 of the Condensed Notes to Consolidated Financial Statements included in “Item 1. Consolidated Financial Statements (Unaudited)” for additional information regarding our commodity derivative positions at September 30, 2017 and additional derivative contracts entered into subsequent to September 30, 2017, respectively.

Oil and natural gas prices have been subject to significant fluctuations during the past several years. The average oil and natural gas prices were higher during the comparable periods of 2017 measured against 2016. The following table sets forth the average New York Mercantile Exchange (“NYMEX”) oil and natural gas prices for the three and nine months ended September 30, 2017 and 2016, as well as the high and low NYMEX prices for the same periods:

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2017	**2016**	**2017**	**2016**
Average NYMEX prices:				
Oil (Bbl)	$ 48.12	$ 45.03	$ 49.45	$ 41.45
Natural gas (MMBtu)	$ 2.95	$ 2.80	$ 3.06	$ 2.35
High and Low NYMEX prices:				
Oil (Bbl):				
High	$ 52.22	$ 48.99	$ 54.45	$ 51.23
Low	$ 44.23	$ 39.51	$ 42.53	$ 26.21
Natural gas (MMBtu):				

High	$	3.15	$	3.06	$	3.72	$	3.06
Low	$	2.77	$	2.55	$	2.56	$	1.64

Further, the NYMEX oil price and NYMEX natural gas price reached highs and lows of $54.15 and $49.29 per Bbl and $3.01 and $2.75 per MMBtu, respectively, during the period from October 1, 2017 to October 30, 2017. At October 30, 2017, the NYMEX oil price and NYMEX natural gas price were $54.15 per Bbl and $2.97 per MMBtu, respectively.

Historically, and during the nine months ended September 30, 2017, we derived a significant portion of our total natural gas revenues from the value of the natural gas liquids contained in our natural gas, with the remaining portion coming from the value of the dry natural gas residue. The average Mont Belvieu price for a blended barrel of natural gas liquids was $25.04 per Bbl and $17.82 per Bbl during the three months ended September 30, 2017 and 2016, respectively, and $23.74 per Bbl and $16.82 per Bbl during the nine months ended September 30, 2017 and 2016, respectively.

Recent Events

Senior notes. In September 2017, we issued $1,800 million in aggregate principal amount of unsecured senior notes, consisting of $1,000 million in aggregate principal amount of 3.75% unsecured senior notes due 2027 (the “3.75% Notes”) and $800 million in aggregate principal amount of 4.875% unsecured senior notes due 2047 (the “4.875% Notes” and, together with the 3.75% Notes, the “Notes”). We used the net proceeds of approximately $1,777 million, together with cash on hand and borrowings under the Credit Facility, as defined below, to fund the cash tender offer (the “Tender Offer”) and the satisfaction and discharge of the outstanding $600 million aggregate principal amount of our 5.5% unsecured senior notes due 2022 and the outstanding $1,550 million aggregate principal amount of our 5.5% unsecured senior notes due 2023 (collectively, the “5.5% Notes”). As a result of these transactions, we recorded a loss on extinguishment of debt related to the 5.5% Notes of approximately $65 million during each of the three and nine months ended September 30, 2017. See Note 8 of the Condensed Notes to Consolidated Financial Statements included in “Item 1. Consolidated Financial Statements (Unaudited)” for additional information regarding our senior notes.

Investment grade period. In September 2017, we elected to enter into an “Investment Grade Period” under the amended and restated credit facility (the “Credit Facility”), which had the effect of releasing all collateral formerly securing the Credit Facility. If the Investment Grade Period under the Credit Facility terminates (whether automatically due to a downgrade of our credit ratings below certain thresholds or by our election), the Credit Facility will once again be secured by a first lien on substantially all of our oil and natural gas properties and by a pledge of the equity interests in our subsidiaries. Additionally, as a result of our Investment Grade Period election along with amendments to certain International Swap Dealers Association Master Agreements (“ISDA Agreements”) with our derivative counterparties, our derivatives are no longer secured.

Midland Basin acquisition. In July 2017, we completed an acquisition in the Midland Basin. As consideration for the acquisition, we paid approximately $595 million in cash. The acquisition is subject to customary post-closing adjustments. Concurrent with the acquisition, we entered into a transaction structured as a reverse like-kind exchange in accordance with Section 1031 of the Internal Revenue Code of 1986. See Note 4 of the Condensed Notes to Consolidated Financial Statements included in “Item 1. Consolidated Financial Statements (Unaudited)” for additional information regarding this transaction.

Derivative Financial Instruments

Derivative financial instrument exposure. At September 30, 2017, the fair value of our financial derivatives was a net liability of $11 million. Under the terms of our financial derivative instruments, we do not have exposure to potential "margin calls" on our financial derivative instruments. We currently have no reason to believe that our counterparties to these commodity derivative contracts are not financially viable. The terms of our Credit Facility do not allow us to offset amounts we may owe a lender against amounts we may be owed related to our financial instruments with such party. In September 2017, we elected to enter into an Investment Grade Period under the Credit Facility, which had the effect of releasing all collateral formerly securing the Credit Facility and derivative obligations. See Note 8 of the Condensed Notes to Consolidated Financial Statements included in "Item 1. Consolidated Financial Statements (Unaudited)" for additional information regarding our Credit Facility.

New commodity derivative contracts. After September 30, 2017, we entered into the following oil price swaps, oil basis swaps and natural gas price swaps to hedge additional amounts of our estimated future production:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Price Swaps: (a)					
2017:					
Volume (Bbl)				846,000	846,000
Price per Bbl				$ 51.29	$ 51.29
2018:					
Volume (Bbl)	953,000	600,000	407,000	296,000	2,256,000
Price per Bbl	$ 51.55	$ 51.39	$ 51.43	$ 51.28	$ 51.45
2019:					
Volume (Bbl)	1,035,000	1,046,500	828,000	828,000	3,737,500
Price per Bbl	$ 51.25	$ 51.25	$ 51.14	$ 51.14	$ 51.20
Oil Basis Swaps: (b)					
2017:					
Volume (Bbl)				1,499,000	1,499,000
Price per Bbl				$ (0.12)	$ (0.12)
2018:					
Volume (Bbl)	540,000	546,000	276,000	276,000	1,638,000
Price per Bbl	$ (0.21)	$ (0.21)	$ (0.38)	$ (0.38)	$ (0.27)
2019:					
Volume (Bbl)	1,395,000	1,410,500	1,426,000	1,426,000	5,657,500
Price per Bbl	$ (0.68)	$ (0.68)	$ (0.68)	$ (0.68)	$ (0.68)
Natural Gas Price Swaps: (c)					
2017:					
				3,660,000	3,660,000

Volume (MMBtu)					
Price per MMBtu				$ 3.02	$ 3.02
2018:					
Volume (MMBtu)	5,400,000	5,460,000	4,600,000	4,600,000	20,060,000
Price per MMBtu	$ 3.02	$ 3.02	$ 3.01	$ 3.01	$ 3.02
2019:					
Volume (MMBtu)	1,800,000	1,820,000	1,840,000	1,840,000	7,300,000
Price per MMBtu	$ 2.86	$ 2.86	$ 2.86	$ 2.86	$ 2.86

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

(b) The basis differential price is between Midland – WTI and Cushing – WTI.

(c) The index prices for the natural gas price swaps are based on the NYMEX – Henry Hub last trading day futures price.

Results of Operations

The following table sets forth summary information concerning our production and operating data for the three and nine months ended September 30, 2017 and 2016. The actual historical data in this table excludes results from our acquisition from Reliance Energy, Inc. (the "Reliance Acquisition") for periods prior to October 2016. Because of normal production declines, increased or decreased drilling activities, fluctuations in commodity prices and the effects of our acquisitions or divestitures, the historical information presented below should not be interpreted as being indicative of future results.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	**2016**	**2017**	**2016**
Production and operating data:				
Average daily production volumes:				
Oil (Bbl)	119,565	91,120	115,484	89,854
Natural gas (Mcf)	441,587	370,609	425,791	336,084
Total (Boe)	193,163	152,888	186,449	145,868
Average prices per unit:				
Oil, without derivatives (Bbl)	$ 45.29	$ 41.52	$ 46.34	$ 37.75
Oil, with derivatives (Bbl) (a)	$ 47.81	$ 59.87	$ 50.45	$ 60.74
Natural gas, without derivatives (Mcf)	$ 3.18	$ 2.42	$ 2.96	$ 1.97
Natural gas, with derivatives (Mcf) (a)	$ 3.22	$ 2.46	$ 2.94	$ 2.14
Total, without derivatives (Boe)	$ 35.29	$ 30.61	$ 35.47	$ 27.78
Total, with derivatives (Boe) (a)	$ 36.96	$ 41.65	$ 37.95	$ 42.35
Operating costs and expenses per Boe:				
Oil and natural gas production	$ 5.99	$ 4.98	$ 5.76	$ 6.00
Production and ad valorem taxes	$ 2.70	$ 2.38	$ 2.75	$ 2.23
Depreciation, depletion and amortization	$ 16.00	$ 21.27	$ 16.66	$ 22.27
General and administrative	$ 3.60	$ 3.80	$ 3.56	$ 4.02

(a) Includes the effect of net cash receipts from (payments on) derivatives:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	**2017**	**2016**	**2017**	**2016**

Net cash receipts from (payments on) derivatives:								
Oil derivatives	$	28	$	154	$	129	$	566
Natural gas derivatives		2		1		(3)		16
Total	$	30	$	155	$	126	$	582

The presentation of average prices with derivatives is a result of including the net cash receipts from (payments on) commodity derivatives that are presented in our statements of cash flows. This presentation of average prices with derivatives is a means by which to reflect the actual cash performance of our commodity derivatives for the respective periods and presents oil and natural gas prices with derivatives in a manner consistent with the presentation generally used by the investment community.

Three Months Ended September 30, 2017 Compared to Three Months Ended September 30, 2016

Oil and natural gas revenues. Revenue from oil and natural gas operations was $627 million for the three months ended September 30, 2017, an increase of $197 million (46 percent) from $430 million for 2016. This increase was primarily due to the increase in oil and natural gas production as well as the increase in realized oil and natural gas prices (excluding the effects of derivative activities). Specific factors affecting oil and natural gas revenues include the following:

- average daily oil production was 119,565 Bbl for the three months ended September 30, 2017, an increase of 28,445 Bbl (31 percent) from 91,120 Bbl for 2016;

- average realized oil price (excluding the effects of derivative activities) was $45.29 per Bbl during the three months ended September 30, 2017, an increase of 9 percent from $41.52 per Bbl during 2016. For the three months ended September 30, 2017, our crude oil price differential relative to NYMEX was $(2.83) per Bbl, or a realization of approximately 94 percent, as compared to a crude oil price differential relative to NYMEX of $(3.51) per Bbl, or a realization of approximately 92 percent, for 2016. The basis differential between the location of Midland, Texas and Cushing, Oklahoma (NYMEX pricing location) for our oil directly impacts our realized oil price. For the three months ended September 30, 2017 and 2016, the average market basis differential between WTI-Midland and WTI-Cushing was a price reduction of $0.75 per Bbl and $0.31 per Bbl, respectively. Additionally, we incur fixed deductions from the posted Midland oil price based on the location of our oil within the Permian Basin. These fixed deductions were less per Boe during the three months ended September 30, 2017 as compared to 2016 primarily due to more production transported through pipelines;

- average daily natural gas production was 441,587 Mcf for the three months ended September 30, 2017, an increase of 70,978 Mcf (19 percent) from 370,609 Mcf for 2016; and

- average realized natural gas price (excluding the effects of derivative activities) was $3.18 per Mcf during the three months ended September 30, 2017, an increase of 31 percent from $2.42 per Mcf during 2016. For the three months ended September 30, 2017 and 2016, we realized approximately 108 percent and 86 percent, respectively, of the average NYMEX natural gas prices for the respective periods. The increase in our realized natural gas price (excluding the effects of derivatives) as a percentage of NYMEX during the three months ended September 30, 2017 as compared to 2016 was primarily due to an increase in the average Mont Belvieu price for a blended barrel of natural gas liquids. Historically, and during the three months ended September 30, 2017, we derived a significant portion of our total natural gas revenues from the value of the natural gas liquids contained in our natural gas, with the remaining portion coming from the value of the dry natural gas residue. The average Mont Belvieu price for a blended barrel of natural gas liquids was $25.04 per Bbl and $17.82 per Bbl during the three months ended September 30, 2017 and 2016, respectively.

Oil and natural gas production expenses. The following table provides the components of our oil and natural gas production expenses for the three months ended September 30, 2017 and 2016:

	Three Months Ended September 30,			
	2017		2016	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Lease operating expenses	$ 100	$ 5.68	$ 66	$ 4.63
Workover costs	6	0.31	5	0.35
Total oil and natural gas production expenses	$ 106	$ 5.99	$ 71	$ 4.98

Lease operating expenses were $100 million ($5.68 per Boe) for the three months ended September 30, 2017, which was an increase of $34 million from $66 million ($4.63 per Boe) during 2016. The increase in lease operating expenses during the third quarter of 2017 as compared to 2016 was primarily due to (i) increased production associated with our wells successfully drilled and completed in 2016 and 2017, (ii) our acquisitions during the fourth quarter of 2016 and first nine months of 2017 and (iii) an increase in cost of services. The increase in lease operating expenses per Boe was primarily due to the increase in lease operating expenses noted above including higher expenses per Boe on properties associated with our recent acquisitions in the fourth quarter of 2016 and first nine months of 2017.

Production and ad valorem taxes. The following table provides the components of our production and ad valorem tax expenses for the three months ended September 30, 2017 and 2016:

	Three Months Ended September 30,			
	2017		2016	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Production taxes	$ 44	$ 2.48	$ 31	$ 2.25
Ad valorem taxes	4	0.22	2	0.13
Total production and ad valorem taxes	$ 48	$ 2.70	$ 33	$ 2.38

Production taxes per unit of production were $2.48 per Boe during the three months ended September 30, 2017, an increase of 10 percent from $2.25 per Boe during 2016. Over the same period, our revenue per Boe (excluding the effects of derivatives) increased 15 percent. The increase in production taxes per unit of production was directly related to the increase in oil and natural gas sales, partially offset by a higher percentage of our total production originating in Texas, which has a lower tax rate than New Mexico. Production taxes fluctuate with the market value of our production sold, while ad valorem taxes are generally based on the valuation of our oil and natural gas properties at the beginning of the year, which vary across the different areas in which we operate.

Exploration and abandonments expense. The following table provides the components of our exploration and abandonments expense for the three months ended September 30, 2017 and 2016:

(in millions)		**Three Months Ended September 30, 2017**		**2016**
Geological and geophysical	$	2	$	2
Exploratory dry hole costs		-		-
Leasehold abandonments		5		8
Other		-		-
Total exploration and abandonments	$	7	$	10

Our geological and geophysical expense for the periods presented above primarily consists of the costs of acquiring and processing geophysical data and core analysis.

For the three months ended September 30, 2017 and 2016, we recorded approximately $5 million and $8 million, respectively, of leasehold abandonments. For the three months ended September 30, 2017, our abandonments were primarily related to drilling locations in our Northern Delaware Basin and New Mexico Shelf core areas which, based on multiple factors, are no longer likely to be drilled and acreage in our Southern Delaware Basin core area where we have no future development plans. For the three months ended September 30, 2016, our abandonments were primarily related to expiring acreage.

Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the three months ended September 30, 2017 and 2016:

	Three Months Ended September 30, 2017				**2016**			
(in millions, except per unit amounts)		**Amount**		**Per Boe**		**Amount**		**Per Boe**
Depletion of proved oil and natural gas properties	$	279	$	15.67	$	294	$	20.88
Depreciation of other property and equipment		5		0.31		5		0.36
Amortization of intangible assets - operating rights		-		0.02		-		0.03
Total depletion, depreciation and amortization	$	284	$	16.00	$	299	$	21.27
Oil price used to estimate proved oil reserves at period end	$	46.27			$	38.17		
	$	3.00			$	2.28		

Natural gas price used to estimate proved natural gas reserves
at period end

Depletion of proved oil and natural gas properties was $279 million ($15.67 per Boe) for the three months ended September 30, 2017 and $294 million ($20.88 per Boe) for 2016. The decrease in depletion expense was primarily due to a lower depletion rate per Boe period over period partially offset by an increase in production. The decrease in depletion expense per Boe period over period was primarily due to (i) lower drilling and completion costs per Boe of proved developed reserves added and (ii) an overall increase in proved reserves period over period primarily due to our successful exploratory drilling program, the Reliance Acquisition, the Northern Delaware Basin acquisition, the Midland Basin acquisition, reductions in future estimated lease operating expenses and an increase in commodity prices period over period, partially offset by decreased proved reserves caused by reclassification of proved undeveloped reserves to unproved reserves because they are no longer expected to be developed within five years of their initial recording.

Impairments of long-lived assets. We periodically review our long-lived assets to be held and used, including proved oil and natural gas properties and their integrated assets, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable, for instance when there are declines in commodity prices or well performance. We review our oil and natural gas properties by depletion base. An impairment loss is indicated if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. If the estimated undiscounted future net cash flows are less than the carrying amount of our assets, we recognize an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset.

We estimate undiscounted future net cash flows of our long-lived assets and their integrated assets using management's assumptions and expectations of (i) commodity prices, which are based on the NYMEX strip, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) production volumes, (vi) estimated proved reserves and risk-adjusted probable and possible reserves, and (vii) prevailing market rates of income and expenses from integrated assets. At September 30, 2017, our estimates of commodity prices for purposes of determining undiscounted future cash flows, which are based on the NYMEX strip, ranged from a 2017 price of $52.29 per barrel of oil decreasing to a 2021 price of $50.77 per barrel of oil partially recovering to a 2024 price of $52.01 per barrel of oil. Similarly, natural gas prices ranged from a 2017 price of $3.14 per Mcf of natural gas decreasing to a 2020 price of $2.85 per Mcf of natural gas partially recovering to a 2024 price of $2.88 per Mcf of natural gas. Commodity prices for this purpose were held flat after 2024.

We estimate fair values of our long-lived assets and their integrated assets using a discounted future cash flow model. Fair value assumptions associated with the calculation of discounted future net cash flows include (i) market estimates of commodity prices, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) production volumes, (vi) estimated proved reserves and risk-adjusted probable and possible reserves, (vii) prevailing market rates of income and expenses from integrated assets and (viii) discount rate. The expected future net cash flows were discounted using an annual rate of 10 percent to determine fair value. We did not recognize an impairment charge during the three months ended September 30, 2017 or 2016.

It is reasonably possible that the estimate of undiscounted future net cash flows of our long-lived assets may change in the future resulting in the need to impair carrying values. The primary factors that may affect estimates of future net cash flows are (i) commodity futures prices, (ii) increases or decreases in production and capital costs, (iii) future reserve volume adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves, (iv) results of future drilling activities and (v) prevailing market rates of income and expenses from integrated assets.

Based on economic factors at September 30, 2017, we determined that undiscounted future cash flows attributable to our North Basin Bone Spring ("NBBS") field located in the Northern Delaware Basin with a net book value of approximately $1.1 billion indicated that its carrying amount was expected to be recovered; however, it may be at risk for impairment if management's estimates of future cash flows decline, including as a result of further declines in projected commodity prices (and the resulting impact of future cash flows). We estimate that if the future oil and natural gas prices used in this analysis, and noted above, would have been approximately 10 percent lower at September 30, 2017 with no other changes in capital costs, operating costs, price differentials, or reserve performance curves, we could have recognized a non-cash impairment in that period of approximately $470 million related to our NBBS field. Other assumptions such as operating costs, well and reservoir performance, severance and ad valorem taxes, and operating and development plans would likely change given a change in oil and natural gas prices.

However, we did not estimate the correlation between these assumptions and any estimated commodity price change, and these and other assumptions may worsen or partially mitigate some of the effects of a reduction in commodity prices, including the ultimate impact and amount of any potential impairment charge. As a result, we are unable to predict with certainty whether or not a decline in commodity prices alone will cause us to recognize an impairment charge in a particular field or the magnitude of any such impairment charge. We additionally note that there may be changes to both drilling and completion designs that affect the volume curves, capital costs estimates, and the amount of proved undeveloped locations that can be recorded, each of which will affect management's estimates of future cash flows.

General and administrative expenses. The following table provides components of our general and administrative expenses for the three months ended September 30, 2017 and 2016:

	Three Months Ended September 30,			
	2017		2016	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
General and administrative expenses	$ 51	$ 2.89	$ 42	$ 3.04
Less: Operating fee reimbursements	(4)	(0.24)	(4)	(0.29)
Non-cash stock-based compensation	17	0.95	15	1.05
Total general and administrative expenses	$ 64	$ 3.60	$ 53	$ 3.80

General and administrative expenses were approximately $64 million ($3.60 per Boe) for the three months ended September 30, 2017, an increase of $11 million (21 percent) from $53 million ($3.80 per Boe) for 2016. The increase in cash general and administrative expenses was primarily driven by increased compensation expense as a result of increased employee headcount. The increase in non-cash stock-based compensation was primarily due to the increase in employee headcount coupled with lower forfeitures in the third quarter of 2017. The decrease in total general and administrative expenses per Boe was primarily due to increased production period over period, partially offset by the increase in general and administrative costs noted above.

We receive fees for the operation of jointly-owned oil and natural gas properties during the drilling and production phases and record such reimbursements as reductions to general and administrative expenses in the consolidated statements of operations. We earned reimbursements of approximately $4 million for each of the three months ended September 30, 2017 and 2016.

Gain (loss) on derivatives. The following table sets forth the gain (loss) on derivatives for the three months ended September 30, 2017 and 2016:

(in millions)	Three Months Ended September 30, 2017		2016	
Gain (loss) on derivatives:				
Oil derivatives	$	(205)	$	36
Natural gas derivatives		(1)		5
Total	$	(206)	$	41

The following table represents our net cash receipts from derivatives for the three months ended September 30, 2017 and 2016:

(in millions)	Three Months Ended September 30, 2017		2016	
Net cash receipts from derivatives:				
Oil derivatives	$	28	$	154
Natural gas derivatives		2		1
Total	$	30	$	155

Our earnings are affected by the changes in value of our derivatives portfolio between periods and the related cash settlements of those derivatives, which could be significant. To the extent the future commodity price outlook declines between measurement periods, we will have mark-to-market gains, while to the extent the future commodity price outlook increases between measurement periods, we will have mark-to-market losses. See Note 6 of the Condensed Notes to Consolidated Financial Statements included in “Item 1. Consolidated Financial Statements (Unaudited)” for additional information regarding significant judgments made in classifying financial instruments in the fair value hierarchy.

Interest expense. Interest expense was $39 million for the three months ended September 30, 2017 as compared to $53 million during 2016. The decrease was primarily due to (i) approximately $11 million of interest expense related to our $600 million 7.0% unsecured senior notes due 2021 (the “7.0% Notes”) that were redeemed in September 2016 and (ii) approximately $10 million of interest expense related to our $600 million 6.5% unsecured senior notes due 2022 (the “6.5% Notes”) that were satisfied and discharged in December 2016, partially offset by approximately $7 million of interest expense related to our $600 million 4.375% unsecured senior notes due 2025 (the “4.375% Notes”) issued in December 2016.

Loss on extinguishment of debt. We recorded a loss on extinguishment of debt of approximately $65 million for the three months ended September 30, 2017. This amount includes approximately $36 million associated with the premium paid for the Tender Offer, approximately $25 million associated with the make-whole premium paid for the early extinguishment of the 5.5% Notes, approximately $21 million of unamortized deferred loan costs and approximately $2 million of additional interest on the 5.5% Notes to October 13, 2017, which was paid in September 2017, reduced by approximately $19 million of unamortized premium.

We recorded a loss on extinguishment of debt of approximately $28 million for the three months ended September 30, 2016. This amount includes $21 million associated with the make-whole premium paid for the early redemption of our 7.0% Notes and approximately $7 million of unamortized deferred loan costs.

Income tax provisions. We recorded an income tax benefit of $66 million and $30 million for the three months ended September 30, 2017 and 2016, respectively. The change in our income tax provision was primarily due to the increase in our net loss before income taxes. The effective income tax rates for the three months ended September 30, 2017 and 2016 were 36.7 percent and 37.3 percent, respectively.

Nine Months Ended September 30, 2017 Compared to Nine Months Ended September 30, 2016

Oil and natural gas revenues. Revenue from oil and natural gas operations was $1,806 million for the nine months ended September 30, 2017, an increase of $696 million (63 percent) from $1,110 million for 2016. This increase was primarily due to the increase in oil and natural gas production as well as the increase in realized oil and natural gas prices (excluding the effects of derivative activities). Specific factors affecting oil and natural gas revenues include the following:

- average daily oil production was 115,484 Bbl for the nine months ended September 30, 2017, an increase of 25,630 Bbl (29 percent) from 89,854 Bbl for 2016;

- average realized oil price (excluding the effects of derivative activities) was $46.34 per Bbl during the nine months ended September 30, 2017, an increase of 23 percent from $37.75 per Bbl during 2016. For the nine months ended September 30, 2017, our crude oil price differential relative to NYMEX was $(3.11) per Bbl, or a realization of approximately 94 percent, as compared to a crude oil price differential relative to NYMEX of $(3.70) per Bbl, or a realization of approximately 91 percent, for 2016. The basis differential between the location of Midland, Texas and Cushing, Oklahoma (NYMEX pricing location) for our oil directly impacts our realized oil price. For the nine months ended September 30, 2017 and 2016, the average market basis differential between WTI-Midland and WTI-Cushing was a price reduction of $0.31 per Bbl and $0.11 per Bbl, respectively. Additionally, we incur fixed deductions from the posted Midland oil price based on the location of our oil within the Permian Basin. These fixed deductions were less per Boe during the nine months ended September 30, 2017 as compared to 2016 primarily due to more production transported through pipelines and successful renegotiation of fixed deductions for trucked volumes;

- average daily natural gas production was 425,791 Mcf for the nine months ended September 30, 2017, an increase of 89,707 Mcf (27 percent) from 336,084 Mcf for 2016; and

- average realized natural gas price (excluding the effects of derivative activities) was $2.96 per Mcf during the nine months ended September 30, 2017, an increase of 50 percent from $1.97 per Mcf during 2016. For the nine months ended September 30, 2017 and 2016, we realized approximately 97 percent and 84 percent, respectively, of the average NYMEX natural gas prices for the respective periods. The increase in our realized natural gas price (excluding the effects of derivatives) as a percentage of NYMEX during the nine months ended September 30, 2017 as compared to 2016 was primarily due to an increase in the average Mont Belvieu price for a blended barrel of natural gas liquids. Historically, and during the nine months ended September 30, 2017, we derived a significant portion of our total natural gas revenues from the value of the natural gas liquids contained in our natural gas, with the remaining portion coming from the value of the dry natural gas residue. The average Mont Belvieu price for a blended barrel of natural gas liquids was $23.74 per Bbl and $16.82 per Bbl during the nine months ended September 30, 2017 and 2016, respectively.

During December 2015, a third-party natural gas processing plant located in the Northern Delaware Basin became inoperable following an explosion. We estimate that this event negatively impacted production for the nine months ended September 30, 2016 by approximately 1.6 MBoepd. The plant became fully operational during April 2016.

Oil and natural gas production expenses. The following table provides the components of our oil and natural gas production expenses for the nine months ended September 30, 2017 and 2016:

	Nine Months Ended September 30,			
	2017		2016	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Lease operating expenses	$ 278	$ 5.47	$ 225	$ 5.62
Workover costs	15	0.29	15	0.38
Total oil and natural gas production expenses	$ 293	$ 5.76	$ 240	$ 6.00

Lease operating expenses were $278 million ($5.47 per Boe) for the nine months ended September 30, 2017, which was an increase of $53 million from $225 million ($5.62 per Boe) during 2016. The increase in lease operating expenses during the nine months ended September 30, 2017 as compared to 2016 was primarily due to (i) increased production associated with our wells successfully drilled and completed in 2016 and 2017, (ii) our acquisitions during the fourth quarter of 2016 and first nine months of 2017 and (iii) increased cost of services, partially offset by a decrease in facility expense. The decrease in lease operating expenses per Boe was primarily due to increased production during the first nine months of 2017 as compared to 2016, partially offset by the increase in total lease operating expenses as noted above.

Production and ad valorem taxes. The following table provides the components of our production and ad valorem tax expenses for the nine months ended September 30, 2017 and 2016:

	Nine Months Ended September 30,			
	2017		2016	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Production taxes	$ 128	$ 2.52	$ 78	$ 1.96
Ad valorem taxes	12	0.23	11	0.27
Total production and ad valorem taxes	$ 140	$ 2.75	$ 89	$ 2.23

Production taxes per unit of production were $2.52 per Boe during the nine months ended September 30, 2017, an increase of 29 percent from $1.96 per Boe during 2016. Over the same period, our revenue per Boe (excluding the effects of derivatives) increased 28 percent. The increase in production taxes per unit of production was directly related to the increase in oil and natural gas sales. Additionally, tax credits of approximately $4 million were received during the first quarter of 2016 related to certain wells in Texas qualifying for reduced severance tax rates. Production taxes fluctuate with the market value of our production sold, while ad valorem taxes are generally based on the valuation of our oil and natural gas properties at the beginning of the year, which vary across the different areas in which we operate.

Exploration and abandonments expense. The following table provides the components of our exploration and abandonments expense for the nine months ended September 30, 2017 and 2016:

	Nine Months Ended September 30,	
(in millions)	**2017**	**2016**
Geological and geophysical	$ 9	$ 6
Exploratory dry hole costs	-	7
Leasehold abandonments	29	40
Other	4	1
Total exploration and abandonments	$ 42	$ 54

Our geological and geophysical expense for the periods presented above primarily consists of the costs of acquiring and processing geophysical data and core analysis.

Our exploratory dry hole costs during the nine months ended September 30, 2016 were primarily related to an uneconomic well in our Northern Delaware Basin core area that was attempting to establish commercial production through testing of multiple zones. We did not recognize any exploratory dry hole costs during the nine months ended September 30, 2017.

For the nine months ended September 30, 2017 and 2016, we recorded approximately $29 million and $40 million, respectively, of leasehold abandonments. For the nine months ended September 30, 2017, our abandonments were primarily related to (i) non-contiguous acreage expiring in our Southern Delaware Basin core area and (ii) acreage in our Northern Delaware Basin and New Mexico Shelf core areas in locations where we have no future plans to drill. For the nine months ended September 30, 2016, our abandonments were primarily related to (i) drilling locations in our Northern Delaware Basin and New Mexico Shelf core areas which, based on multiple factors, are no longer likely to be drilled, (ii) acreage in our Northern Delaware Basin and New Mexico Shelf core areas where we have no future development plans and (iii) expiring acreage.

Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the nine months ended September 30, 2017 and 2016:

	Nine Months Ended September 30,			
	2017		2016	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Depletion of proved oil and natural gas properties	$ 830	$ 16.31	$ 874	$ 21.86
Depreciation of other property and equipment	17	0.33	15	0.38
Amortization of intangible assets - operating rights	1	0.02	1	0.03
Total depletion, depreciation and amortization	$ 848	$ 16.66	$ 890	$ 22.27

Depletion of proved oil and natural gas properties was $830 million ($16.31 per Boe) for the nine months ended September 30, 2017, a decrease of $44 million (5 percent) from $874 million ($21.86 per Boe) for 2016. The decrease in depletion expense was primarily due to a lower depletion rate per Boe period over period partially offset by an increase in production. The decrease in depletion expense per Boe period over period was primarily due to (i) lower drilling and completion costs per Boe of proved developed reserves added, (ii) an overall increase in proved reserves period over period primarily caused by our successful exploratory drilling program, the Reliance Acquisition, the Northern Delaware Basin acquisition, the Midland Basin acquisition, reductions in future estimated lease operating expenses and higher commodity prices period over period, partially offset by decreased proved reserves caused by reclassification of proved undeveloped reserves to unproved reserves because they are no longer expected to be developed within five years of their initial recording and (iii) a non-cash impairment charge of approximately $1.5 billion recorded in the first quarter of 2016.

Impairments of long-lived assets. We periodically review our long-lived assets to be held and used, including proved oil and natural gas properties and their integrated assets, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable, for instance when there are declines in commodity prices or well performance. We review our oil and natural gas properties by depletion base. An impairment loss is indicated if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. If the estimated undiscounted future net cash flows are less than the carrying amount of our assets, we recognize an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset.

We estimate undiscounted future net cash flows of our long-lived assets and their integrated assets using management's assumptions and expectations of (i) commodity prices, which are based on the NYMEX strip, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) production volumes, (vi) estimated proved reserves and risk-adjusted probable and possible reserves, and (vii) prevailing market rates of income and expenses from integrated assets. At September 30, 2017, our estimates of commodity prices for purposes of determining undiscounted future cash flows, which are based on the NYMEX strip, ranged from a 2017 price of $52.29 per barrel of oil decreasing to a 2021 price of $50.77 per barrel of oil partially recovering to a 2024 price of $52.01 per barrel of oil. Similarly, natural gas prices ranged from a 2017 price of $3.14 per Mcf of natural gas decreasing to a 2020 price of $2.85 per Mcf of natural gas partially recovering to a 2024 price of $2.88 per Mcf of natural gas. Commodity prices for this purpose were held flat after 2024.

We estimate fair values of our long-lived assets and their integrated assets using a discounted future cash flow model. Fair value assumptions associated with the calculation of discounted future net cash flows include (i) market estimates of commodity prices, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) production volumes, (vi) estimated proved reserves and risk-adjusted probable and possible reserves, (vii) prevailing market rates of income and expenses from integrated assets and (viii) discount rate. The expected future net cash flows were discounted using an annual rate of 10 percent to determine fair value.

During the three months ended March 31, 2016, NYMEX strip prices declined as compared to December 31, 2015, and as a result the carrying amount of our Yeso field in our New Mexico Shelf core area exceeded the expected undiscounted future net cash flows resulting in a non-cash charge against earnings of approximately $1.5 billion. The Yeso field, as compared to our other fields not previously impaired, had significant proved reserves upon acquisition, which required a higher valuation than a field more exploratory in nature that has a higher risk factor adjustment in the fair value estimate. Our estimates of commodity prices for purposes of determining the estimated fair value at March 31, 2016 ranged from a 2016 price of $41.26 per barrel of oil and $2.26 per Mcf of natural gas to a 2023 price of $66.33 per barrel of oil and $3.56 per Mcf of natural gas. Commodity prices for this purpose were held flat after 2023. We did not recognize an impairment charge during the nine months ended September 30, 2017.

It is reasonably possible that the estimate of undiscounted future net cash flows of our long-lived assets may change in the future resulting in the need to impair carrying values. The primary factors that may affect estimates of future net cash flows are (i) commodity futures prices, (ii) increases or decreases in production and capital costs, (iii) future reserve volume adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves, (iv) results of future drilling activities and (v) prevailing market rates of income and expenses from integrated assets.

Based on economic factors at September 30, 2017, we determined that undiscounted future cash flows attributable to our NBBS field located in the Northern Delaware Basin with a net book value of approximately $1.1 billion indicated that its carrying amount was expected to be recovered; however, it may be at risk for impairment if management's estimates of future cash flows decline, including as a result of further declines in projected commodity prices (and the resulting impact of future cash flows). We estimate that if the future oil and natural gas prices used in this analysis, and noted above, would have been approximately 10 percent lower at September 30, 2017 with no other changes in capital costs, operating costs, price differentials, or reserve performance curves, we could have recognized a non-cash impairment in that period of approximately $470 million related to our NBBS field. Other assumptions such as operating costs, well and reservoir performance, severance and ad valorem taxes, and operating and development plans would likely change given a change in oil and natural gas prices. However, we did not estimate the correlation between these assumptions and any estimated commodity price change, and these and other assumptions may worsen or partially mitigate some of the effects of a reduction in commodity prices, including the ultimate impact and amount of any potential impairment charge. As a result, we are unable to predict with certainty whether or not a decline in commodity prices alone will cause us to recognize an impairment charge in a particular field or the magnitude of any such impairment charge. We additionally note that there may be changes to both drilling and completion designs that affect the volume curves, capital costs estimates, and the amount of proved undeveloped locations that can be recorded, each of which will affect management's estimates of future cash flows.

General and administrative expenses. The following table provides components of our general and administrative expenses for the nine months ended September 30, 2017 and 2016:

	Nine Months Ended September 30, 2017		2016	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
General and administrative expenses	$ 149	$ 2.95	$ 129	$ 3.24
Less: Operating fee reimbursements	(12)	(0.24)	(12)	(0.30)
Non-cash stock-based compensation	43	0.85	43	1.08
Total general and administrative expenses	$ 180	$ 3.56	$ 160	$ 4.02

General and administrative expenses were approximately $180 million ($3.56 per Boe) for the nine months ended September 30, 2017, an increase of $20 million (13 percent) from $160 million ($4.02 per Boe) for 2016. The increase in cash general and administrative expenses was primarily a result of increased compensation expense. The decrease in total general and administrative expenses per Boe was primarily due to increased production period over period, partially offset by the increase in general and administrative costs noted above.

We receive fees for the operation of jointly-owned oil and natural gas properties during the drilling and production phases and record such reimbursements as reductions of general and administrative expenses in the consolidated statements of operations. We earned reimbursements of approximately $12 million for each of the nine months ended September 30, 2017 and 2016.

Gain (loss) on derivatives. The following table sets forth the gain (loss) on derivatives for the nine months ended September 30, 2017 and 2016:

	Nine Months Ended September 30,	
(in millions)	**2017**	**2016**
Gain (loss) on derivatives:		
Oil derivatives	$ 260	$ (173)
Natural gas derivatives	29	(3)
Total	$ 289	$ (176)

The following table represents our net cash receipts from (payments on) derivatives for the nine months ended September 30, 2017 and 2016:

	Nine Months Ended September 30,	
(in millions)	**2017**	**2016**
Net cash receipts from (payments on) derivatives:		
Oil derivatives	$ 129	$ 566
Natural gas derivatives	(3)	16
Total	$ 126	$ 582

Our earnings are affected by the changes in value of our derivatives portfolio between periods and the related cash settlements of those derivatives, which could be significant. To the extent the future commodity price outlook declines between measurement periods, we will have mark-to-market gains, while to the extent the future commodity price outlook increases between measurement periods, we will have mark-to-market losses. See Note 6 of the Condensed Notes to Consolidated Financial Statements included in “Item 1. Consolidated Financial Statements (Unaudited)” for additional information regarding significant judgments made in classifying financial instruments in the fair value hierarchy.

Gain on disposition of assets, net. In February 2017, we closed on our previously announced divestiture of our ownership interest in ACC. After adjustments for debt and working capital, we received cash proceeds from the sale of approximately $801 million. After direct transaction costs, we recorded a pre-tax gain on disposition of assets of approximately $655 million. Our net investment in ACC at the time of closing was approximately $129 million.

In February 2016, we sold certain assets in the Northern Delaware Basin for proceeds of approximately $292 million and recognized a pre-tax gain of approximately $110 million.

Interest expense. Interest expense was $118 million for the nine months ended September 30, 2017 as compared to $162 million during 2016. The decrease was primarily due to (i) approximately $32 million of interest expense related to our $600 million 7.0% Notes that were redeemed in September 2016 and (ii) approximately $29 million of interest expense related to our $600 million 6.5% Notes that were satisfied and discharged in December 2016, partially offset by approximately $20 million of interest expense related to our $600 million 4.375% Notes issued in December 2016.

Loss on extinguishment of debt. We recorded a loss on extinguishment of debt of approximately $66 million for the nine months ended September 30, 2017. This amount includes (i) approximately $36 million associated with the premium paid for the Tender Offer, approximately $25 million associated with the make-whole premium paid for the early extinguishment of the 5.5% Notes, approximately $21 million of unamortized deferred loan costs and approximately $2 million of additional interest on the 5.5% Notes to October 13, 2017, which was paid in September 2017, reduced by approximately $19 million of unamortized premium; and (ii) approximately $1 million representing the proportional amount of unamortized deferred loan costs associated with banks that are no longer in the credit facility syndicate as a result of the April 2017 credit facility amendment.

We recorded a loss on extinguishment of debt of approximately $28 million for the nine months ended September 30, 2016. This amount includes $21 million associated with the make-whole premium paid for the early redemption of the 7.0% Notes and approximately $7 million of unamortized deferred loan costs.

Income tax provisions. We recorded income tax expense of $398 million, which includes a discrete income tax benefit of approximately $6 million related to excess tax benefits on stock-based awards, which are recorded in the income tax provision pursuant to ASU No. 2016-09, which was adopted on January 1, 2017, and an income tax benefit of $782 million for the nine months ended September 30, 2017 and 2016, respectively. The change in our income tax provision was primarily due to income before income taxes during the nine months ended September 30, 2017, as compared to a loss before income taxes during 2016. The effective income tax rates for the nine months ended September 30, 2017 and 2016 were 36.6 percent and 36.9 percent, respectively.

Capital Commitments, Capital Resources and Liquidity

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

Oil and natural gas properties. Our costs incurred on oil and natural gas properties, excluding acquisitions, during the nine months ended September 30, 2017 and 2016 totaled $1.2 billion and $800 million, respectively. The increase was primarily due to our increased drilling and completion activity level during the first nine months of 2017 as compared to 2016. Our intent is to manage our capital spending to be within our cash flow, excluding unbudgeted acquisitions. The primary reason for the differences in costs incurred and cash flow expenditures was our issuance of approximately 2.2 million shares of common stock related to our Northern Delaware Basin acquisition and timing of payments. Total 2017 expenditures were primarily funded in part from (i) cash flows from operations, (ii) our issuance of approximately 2.2 million shares of common stock related to our Northern Delaware Basin acquisition and to a lesser extent (iii) proceeds from our February 2017 divestiture of ACC.

2017 capital budget. In February 2017, we announced our updated 2017 capital budget, excluding acquisitions, of approximately $1.8 billion with expected capital spending to range between $1.6 billion and $1.8 billion. Approximately 90 percent of capital will be directed to drilling and completion activity. Our 2017 capital program, based on our current expectations of commodity prices and costs, is expected to be within our cash flows. However, if we were to outspend our cash flows, we believe we could use our credit facility and other financing sources to fund any cash flow deficits. The actual amount and timing of our expenditures may differ materially from our estimates as a result of, among other things, actual drilling results, the timing of expenditures by third parties on projects that we do not operate, the costs of drilling rigs and other services and equipment, regulatory, technological and competitive developments, commodity prices, leverage metrics and industry conditions. In addition, under certain circumstances, we may consider increasing, decreasing or reallocating our capital spending plans.

Acquisitions. The following table reflects our expenditures for acquisitions of proved and unproved properties for the nine months ended September 30, 2017 and 2016:

	Nine Months Ended September 30,	
(in millions)	**2017**	**2016**
Property acquisition costs:		
Proved	$ 301	$ 257

Unproved		865		172
Total property acquisition costs (a)	$	1,166	$	429

(a) Included in the property acquisition costs above are budgeted unproved leasehold acreage acquisitions of approximately $26 million for each of the nine months ended September 30, 2017 and 2016. For the nine months ended September 30, 2017, our unbudgeted acquisitions are primarily comprised of approximately $603 million and $452 million of property acquisition costs related to our Midland Basin and Northern Delaware Basin acquisitions, respectively. For the nine months ended September 30, 2016, our unbudgeted acquisitions are primarily comprised of approximately $375 million of property acquisition costs related to our Southern Delaware Basin acquisition.

Contractual obligations. Our contractual obligations include long-term debt, cash interest expense on debt, derivative liabilities, asset retirement obligations, employment agreements with officers, purchase obligations, operating lease obligations and other obligations. Since December 31, 2016, the changes in our contractual obligations are not material, other than our cash interest expense on debt and our derivative liability position. Cash interest expense on debt increased by $854 million due to the issuance of the Notes which have maturity dates of 2027 and 2047, as compared to the retired 5.5% Notes which had maturity dates of 2022 and 2023. Our derivative liability position decreased from December 31, 2016 by $135 million. See Note 8 of the Condensed Notes to Consolidated Financial Statements included in “Item 1. Consolidated Financial Statements (Unaudited)” for additional information regarding our long-term debt and “Item 3. Quantitative and Qualitative Disclosures About Market Risk” for information regarding the interest on our long-term debt and information on changes in the fair value of our open derivative obligations during the nine months ended September 30, 2017.

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

Capital resources. Our primary sources of liquidity have been cash flows generated from (i) operating activities, (ii) borrowings under our credit facility, (iii) proceeds from bond and equity offerings and (iv) asset dispositions. In February 2017, we announced our updated 2017 capital budget, excluding acquisitions, of approximately $1.8 billion with expected capital spending to range between $1.6 billion and $1.8 billion. Our 2017 capital program, based on our current expectations of commodity prices and costs, is expected to be within our cash flows. However, if we were to outspend our cash flows, we believe we could use our credit facility and other financing sources to fund any cash flow deficits. The actual amount and timing of our expenditures may differ materially from our estimates as a result of, among other things, actual drilling results, the timing of expenditures by third parties on projects that we do not operate, the costs of drilling rigs and other services and equipment, regulatory, technological and competitive developments, commodity prices, leverage metrics and industry conditions. In addition, under certain circumstances, we may consider increasing, decreasing or reallocating our capital spending plans.

The following table summarizes our changes in cash and cash equivalents for the nine months ended September 30, 2017 and 2016:

	Nine Months Ended September 30,			
(in millions)		**2017**		**2016**
Net cash provided by operating activities	$	1,185	$	1,019
Net cash used in investing activities		(1,207)		(783)
Net cash provided by (used in) financing activities		(31)		694
Net increase (decrease) in cash and cash equivalents	$	(53)	$	930

Cash flow from operating activities. The increase in operating cash flows during the nine months ended September 30, 2017 as compared to the same period in 2016 was primarily due to an increase in oil and natural gas revenues of approximately $696 million and a decrease in cash interest expense of approximately $42 million, partially offset by (i) approximately $126 million from settlements on derivatives during the nine months ended September 30, 2017, as compared to $582 million from settlements on derivatives during the comparable period in 2016, (ii) approximately $53 million increase in production expense, (iii) approximately $51 million increase in production tax expense and (iv) a decrease in operating cash flow of approximately $20 million due to cash tax expense of approximately $6 million for the nine months ended September 30, 2017, as compared to a cash tax benefit of approximately $14 million during the comparable period in 2016.

Our net cash provided by operating activities included a reduction of approximately $59 million and $73 million for the nine months ended September 30, 2017 and 2016, respectively, associated with changes in working capital items. Changes in working capital items adjust for the timing of receipts and payments of actual cash.

Cash flow from investing activities. During the nine months ended September 30, 2017 and 2016, we invested approximately $1,958 million and $927 million, respectively, for capital expenditures on oil and natural gas properties. Additionally, we received approximately $803 million related to proceeds from the disposition of assets during the nine months ended September 30, 2017, as compared to $296 million during the comparable period of 2016.

Cash flow from financing activities. Net cash used in financing activities was approximately $31 million for the nine months ended September 30, 2017 while net cash provided by financing activities was approximately $694 million for the nine months ended September 30, 2016. Below is a description of our significant financing activities:

- In September 2017, we issued $1,800 million in aggregate principal amount of the Notes, for which we received net proceeds of approximately $1,777 million. We used the net proceeds from the offering, together with cash on hand and borrowings under our credit facility, to fund the (i) Tender Offer of $1,232 million principal amount of our 5.5% Notes at a price equal to 102.934 percent of par and (ii) satisfaction and discharge of our remaining obligations of $918 million principal amount under the indentures of the 5.5% Notes at a price equal to 102.75 percent of par. The early extinguishment price included approximately $36 million associated with the premium paid for the Tender Offer, approximately $25 million for the make-whole premium paid for the early extinguishment of the 5.5% Notes and approximately $2 million for prepaid interest as part of the satisfaction and discharge.

- In September 2016, we redeemed the $600 million outstanding principal amount of our 7.0% Notes at a price equal to 103.5 percent of par. The redemption price included the make-whole premium for the early redemption of $21 million.

- In August 2016, we issued approximately 10.4 million shares of our common stock in a public offering at $130.90 per share and received net proceeds of approximately $1.3 billion.

- During the first nine months of 2017, we borrowed $368 million on our credit facility.

- During the first nine months of 2016, we had no outstanding borrowings under our credit facility.

In April 2017, we amended our credit facility to decrease our unused lender commitments. At September 30, 2017, we had unused commitments on our credit facility of approximately $1.6 billion.

Advances on our Credit Facility bear interest, at our option, based on (i) an alternative base rate, which is equal to the highest of (a) the prime rate of JPMorgan Chase Bank (4.25 percent at September 30, 2017), (b) the federal funds effective rate plus 0.5 percent and (c) the London Interbank Offered Rate ("LIBOR") plus 1.0 percent or (ii) LIBOR. The credit facility's interest rates and commitment fees on the unused portion of the available commitment vary depending on our credit ratings from Moody's Investors Service, Inc. ("Moody's") and S&P Global Ratings ("S&P"). At our current credit ratings, LIBOR Rate Loans and Alternate Base Rate Loans bear interest margins of 150 basis points and 50 basis points per annum, respectively, and commitment fees on the unused portion of the available commitment are 25 basis points per annum. In September 2017, we elected to enter into an Investment Grade Period under our credit facility, which had the effect of releasing all collateral formerly securing the credit facility. If the Investment Grade Period under the credit facility terminates (whether automatically or by our election), the credit facility will once again be secured by a first lien on substantially all of our oil and natural gas properties and by a pledge of the equity interests in our subsidiaries.

In conducting our business, we may utilize various financing sources, including the issuance of (i) fixed and floating rate debt, (ii) convertible securities, (iii) preferred stock, (iv) common stock and (v) other securities. Historically, we have demonstrated our use of the capital markets by issuing common stock and senior unsecured debt. There are no assurances that we can access the capital markets to obtain additional funding, if needed, and at cost and terms that are favorable to us. We may also sell assets and issue securities in exchange for oil and natural gas assets or interests in energy companies. Additional securities may be of a class senior to common stock with respect to such matters as dividends and liquidation rights and may also have other rights and preferences as determined from time to time. Utilization of some of these financing sources may require approval from the lenders under our credit facility.

Liquidity. Our principal source of liquidity is available borrowing capacity under our credit facility. At September 30, 2017, our commitments from our bank group were $2.0 billion.

Debt ratings. We receive debt credit ratings from S&P, Moody’s and Fitch Ratings (“Fitch”), which are subject to regular reviews. In August 2017, our long-term debt was assigned a first-time investment grade rating by Fitch, and our rating by S&P was raised to an investment grade rating. In determining our ratings, the agencies consider a number of qualitative and quantitative factors including, but not limited to: the industry in which we operate, production growth opportunities, liquidity, debt levels and asset and reserve mix. An explanation of the significance of each rating may be obtained from the applicable rating agency.

A downgrade in our credit ratings could (i) negatively impact our costs of capital and our ability to effectively execute aspects of our strategy, (ii) affect our ability to raise debt in the public debt markets, and the cost of any new debt could be much higher than our outstanding debt and (iii) negatively affect our ability to obtain additional financing or the interest rate, fees and other terms associated with such additional financing. Further, if we are unable to maintain credit ratings of “Ba2” or better from Moody’s and “BB” or better from S&P, the Investment Grade Period will automatically terminate and cause the credit facility to once again be secured by a first lien on substantially all of our oil and natural gas properties and by a pledge of the equity interests in our subsidiaries. These and other impacts of a downgrade in our credit ratings could have a material adverse effect on our business, financial condition and results of operations.

As of the filing of this Quarterly Report, no changes in our credit ratings have occurred since September 30, 2017; however, we cannot be assured that our credit ratings will not be downgraded in the future.

Book capitalization and current ratio. Our net book capitalization at September 30, 2017 was $11.3 billion, consisting of debt of $2.7 billion and stockholders’ equity of $8.6 billion. Our net book capitalization at December 31, 2016 was $10.2 billion, consisting of $0.1 billion of cash and cash equivalents, debt of $2.7 billion and stockholders’ equity of $7.6 billion. Our ratio of net debt to net book capitalization was 24 percent and 26 percent at September 30, 2017 and December 31, 2016, respectively. Our ratio of current assets to current liabilities was 0.66 to 1.0 at September 30, 2017 as compared to 0.73 to 1.0 at December 31, 2016.

Inflation and changes in prices. Our revenues, the value of our assets, and our ability to obtain bank financing or additional capital on attractive terms have been and will continue to be affected by changes in commodity prices and the costs to produce our reserves. Commodity prices are subject to significant fluctuations that are beyond our ability to control or predict. During the nine months ended September 30, 2017, we received an average of $46.34 per Bbl of oil and $2.96 per Mcf of natural gas before consideration of commodity derivative contracts compared to $37.75 per Bbl of oil and $1.97 per Mcf of natural gas in the nine months ended September 30, 2016. Although certain of our costs are affected by general inflation, inflation does not normally have a significant effect on our business.

Critical Accounting Policies, Practices and Estimates

Our historical consolidated financial statements and related condensed notes to consolidated financial statements contain information that is pertinent to our management's discussion and analysis of financial condition and results of operations. Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires that our management make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. However, the accounting principles used by us generally do not change our reported cash flows or liquidity. Interpretation of the existing rules must be done and judgments made on how the specifics of a given rule apply to us.

In management's opinion, the more significant reporting areas impacted by management's judgments and estimates are the choice of accounting method for oil and natural gas activities, oil and natural gas reserve estimation, asset retirement obligations, impairment of long-lived assets, valuation of business combinations, valuation of nonmonetary exchanges, valuation of financial derivative instruments, valuation of stock-based compensation and income taxes. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists and historical experience in similar matters. Actual results could differ from the estimates as additional information becomes known.

There have been no material changes in our critical accounting policies and procedures during the nine months ended September 30, 2017. See our disclosure of critical accounting policies in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data" of our Annual Report on Form 10-K for the year ended December 31, 2016, filed with the United States Securities and Exchange Commission (the "SEC") on February 22, 2017.

New accounting pronouncements issued but not yet adopted. In May 2014, the Financial Accounting Standards Board (the "FASB") issued ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)," which outlines a new, single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized. The new model will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services.

In August 2015, the FASB issued ASU No. 2015-14, "Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date," which deferred the effective date of ASU No. 2014-09 by one year. That new standard is now effective for annual reporting periods beginning after December 15, 2017. We expect to use the modified retrospective method to adopt the standard, meaning the cumulative effect of initially applying the standard will be recognized with an adjustment to retained earnings on January 1, 2018. We have substantially completed our internal evaluation of the adoption of this standard, which included a review of all revenue-related contracts with customers and the application of the new revenue recognition model against those contracts. We are also updating our revenue recognition policy to conform to the new standard. We also expect to expand our revenue recognition related disclosure. Including those changes previously discussed, we do not expect this new guidance will have a material impact on our consolidated financial statements.

In February 2016, the Financial Accounting Standards Board (the “FASB”) issued ASU No. 2016-02, “Leases (Topic 842),” which supersedes current lease guidance. The new lease standard requires all leases with a term greater than one year to be recognized on the balance sheet while maintaining substantially similar classifications for finance and operating leases. Lease expense recognition on the income statement will be effectively unchanged. This guidance is effective for reporting periods beginning after December 15, 2018 and early adoption is permitted. We are evaluating the impact that this new guidance will have on our consolidated financial statements.

In January 2017, the FASB issued ASU No. 2017-01, “Business Combinations (Topic 805): Clarifying the Definition of a Business,” with the objective of adding guidance to assist in evaluating whether transactions should be accounted for as asset acquisitions or as business combinations. The guidance provides a screen to determine when an integrated set of assets and activities is not a business. The screen requires that when substantially all of the fair value of the acquired assets is concentrated in a single asset or a group of similar assets, the set is not a business. If the screen is not met, to be considered a business, the set must include an input and a substantive process that together significantly contribute to the ability to create output. This new guidance is effective for annual periods beginning after December 15, 2017, and early adoption is allowed. We are evaluating the impact this new guidance will have on our consolidated financial statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The following market risk disclosures should be read in conjunction with the quantitative and qualitative disclosures about market risk contained in our Annual Report on Form 10-K for the year ended December 31, 2016.

We are exposed to a variety of market risks, including credit risk, commodity price risk and interest rate risk. We address these risks through a program of risk management which includes the use of derivative instruments. The following quantitative and qualitative information is provided about financial instruments to which we are a party at September 30, 2017, and from which we may incur future gains or losses from changes in market interest rates or commodity prices and losses from extension of credit. We do not enter into derivative or other financial instruments for speculative or trading purposes.

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

Credit risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our oil and natural gas production, which we market to energy marketing companies and refineries, and to a lesser extent, our derivative counterparties. We monitor our exposure to these counterparties primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty's creditworthiness.

We have entered into ISDA Agreements with each of our derivative counterparties. The terms of the ISDA Agreements provide us and the counterparties with rights of set-off upon the occurrence of defined acts of default by either us or a counterparty to a derivative, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party. See Note 7 of the Condensed Notes to Consolidated Financial Statements included in "Item 1. Consolidated Financial Statements (Unaudited)" for additional information regarding our derivative activities.

Commodity price risk. We are exposed to market risk as the prices of our commodities are subject to fluctuations resulting from changes in supply and demand. To reduce our exposure to changes in the prices of our commodities, we have entered into, and may in the future enter into, additional commodity price risk management arrangements for a portion of our oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Our commodity price risk management arrangements are recorded at fair value and thus changes to the future commodity prices will have an impact on net income. The following table sets forth the hypothetical impact on the fair value of the commodity price risk management arrangements from an average increase and decrease in the commodity price of $5.00 per Bbl of oil and $0.50 per MMBtu of natural gas from the commodity prices at September 30, 2017:

(in millions)	**Increase of $5.00 per Bbl and $0.50 per MMBtu**	**Decrease of $5.00 per Bbl and $0.50 per MMBtu**
Gain (loss):		
Oil derivatives	$ (289)	$ 289
Natural gas derivatives	(31)	31
Total	$ (320)	$ 320

At September 30, 2017, we had (i) oil price swaps that settle on a monthly basis covering future oil production from October 1, 2017 through December 31, 2019 and (ii) oil basis swaps covering our Midland to Cushing basis differential from October 1, 2017 to December 31, 2019. The average NYMEX oil price for the nine months ended September 30, 2017 was $49.45 per Bbl. At October 30, 2017, the NYMEX oil price was $54.15 per Bbl.

At September 30, 2017, we had natural gas price swaps that settle on a monthly basis covering future natural gas production from October 1, 2017 to December 31, 2019. The average NYMEX natural gas price for the nine months ended September 30, 2017 was $3.06 per MMBtu. At October 30, 2017, the NYMEX natural gas price was $2.97 per MMBtu.

A decrease in the average forward NYMEX oil and natural gas prices below those at September 30, 2017 would decrease the fair value liability of our commodity derivative contracts from their recorded balance at September 30, 2017. Changes in the recorded fair value of our commodity derivative contracts are marked to market through earnings as gains or losses. The potential decrease in our fair value liability would be recorded in earnings as a gain. However, an increase in the average forward NYMEX oil and natural gas prices above those at September 30, 2017 would increase the fair value liability of our commodity derivative contracts from their recorded balance at September 30, 2017. The potential increase in our fair value liability would be recorded in earnings as a loss. We are currently unable to estimate the effects on the earnings of future periods resulting from changes in the market value of our commodity derivative contracts.

The fair value of our derivative instruments is determined based on our valuation models. We did not change our valuation method for our derivative instruments during the nine months ended September 30, 2017. The following table reconciles the changes that occurred in the fair values of our derivative instruments during the nine months ended September 30, 2017:

(in millions)		**Commodity Derivative Instruments Net Assets (Liabilities) (a)**
Fair value of contracts outstanding at December 31, 2016	$	(174)
Changes in fair values (b)		289
Contract maturities		(126)
Fair value of contracts outstanding at September 30, 2017	$	(11)

(a) Represents the fair values of open derivative contracts subject to market risk.
(b) At inception, new derivative contracts entered into by us have no intrinsic value.

See Note 7 of the Condensed Notes to Consolidated Financial Statements included in “Item 1. Consolidated Financial Statements (Unaudited)” for additional information regarding our derivative instruments.

Interest rate risk. Our exposure to changes in interest rates relates primarily to debt obligations. We manage our interest rate exposure by limiting our variable-rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. To reduce our exposure to changes in interest rates we may, in the future, enter into interest rate risk management arrangements for a portion of our outstanding debt. The agreements that we have entered into generally have the effect of providing us with a fixed interest rate for a portion of our variable rate debt. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We are exposed to changes in interest rates as a result of our credit facility, and the terms of our credit facility require us to pay higher interest rate margins as our credit ratings decrease.

We had total indebtedness of $368 million outstanding under our credit facility at September 30, 2017. The impact of a one percent increase in interest rates on this amount of debt would result in increased annual interest expense of approximately $4 million.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As required by Rule 13a-15(b) of 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 Rule 13a-15(e) under the Exchange Act) as of the end of the period covered by this Quarterly Report. 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 or submit 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 the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective at September 30, 2017 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting. There have been no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

We are a party to proceedings and claims incidental to our business. While many of these other matters involve inherent uncertainty, we believe that the liability, if any, ultimately incurred with respect to such other proceedings and claims will not have a material adverse effect on our consolidated financial position as a whole or on our liquidity, capital resources or future results of operations. We will continue to evaluate proceedings and claims involving us on a regular basis and will establish and adjust any reserves as appropriate to reflect our assessment of the then current status of the matters.

Item 1A. Risk Factors

In addition to the information set forth in this Quarterly Report, you should carefully consider the risks discussed in our Annual Report on Form 10-K for the year ended December 31, 2016, under the headings “Item 1. Business — Competition,” “— Marketing Arrangements” and “— Applicable Laws and Regulations,” “Item 1A. Risk Factors,” “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Item 7A. Quantitative and Qualitative Disclosures About Market Risk,” which risks could materially affect our business, financial condition or future results. There have been no material changes in our risk factors from those described in our Annual Report on Form 10-K for the year ended December 31, 2016, other than updating the risk factor below. The risks described in our Annual Report on Form 10-K for the year ended December 31, 2016 and in this Quarterly Report are not the only risks we face. 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 future results. The updated risk factor is as follows:

Future price declines could result in a reduction in the carrying value of our proved oil and natural gas properties, which could adversely affect our results of operations.

Declines in commodity prices may result in us having to make substantial downward adjustments to the value of our estimated proved reserves. If this occurs, or if our estimates of production or economic factors change, accounting rules may require us to write-down, as a non-cash charge to earnings, the carrying value of our proved oil and natural gas properties for impairments. We are required to perform impairment tests on proved assets whenever events or changes in circumstances warrant a review of our proved oil and natural gas properties. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our oil and natural gas properties, the carrying value may not be recoverable and therefore require a write-down. The primary factors that may affect management’s estimates of future cash flows are (i) commodity futures prices, (ii) increases or decreases in production and capital costs, (iii) future reserve volume adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves, (iv) results of future drilling activities and (v) prevailing market rates of income and expenses from integrated assets. We may incur impairment charges in the future, which could materially adversely affect our results of operations in the period incurred.

Based on economic factors at September 30, 2017, we determined that undiscounted future cash flows attributable to our NBBS field with a net book value of approximately $1.1 billion indicated that its carrying amount was expected to be recovered; however, it may be at risk for impairment if management's estimates of future cash flows decline, including as a result of further declines in projected commodity prices (and the resulting impact of future cash flows) subsequent to September 30, 2017. We estimate that if the oil and natural gas prices used in the estimated fair value analysis would have been approximately 10 percent lower at September 30, 2017 with no other changes in capital costs, operating costs, price differentials, or reserve performance curves, we could have recognized a non-cash impairment in that period of approximately $470 million related to our NBBS field. Other assumptions such as operating costs, well and reservoir performance, severance and ad valorem taxes, and operating and development plans would likely change given a change in oil and natural gas prices. However, we are unable to estimate the correlation between these assumptions and any estimated commodity price change, and these and other assumptions may worsen or partially mitigate some of the effects of a reduction in commodity prices, including the ultimate impact and amount of any potential impairment charge. As a result, we are unable to predict with certainty whether or not a decline in commodity prices alone will cause us to recognize an impairment charge in a particular field or the magnitude of any such impairment charge.

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

Period	Total number of shares withheld (a)	Average price per share	Total number of shares purchased as part of publicly announced plans	Maximum number of shares that may yet be purchased under the plan
July 1, 2017 - July 31, 2017	585	$ 121.87	-	
August 1, 2017 - August 31, 2017	5,103	$ 116.37	-	
September 1, 2017 - September 30, 2017	213	$ 123.73	-	

(a) Represents shares that were withheld by us to satisfy tax withholding obligations of certain of our officers and key employees that arose upon the lapse of restrictions on restricted stock.

Item 6. Exhibits

Exhibit Number		Exhibit
3.1		Restated Certificate of Incorporation (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K on August 8, 2007, and incorporated herein by reference).
3.2		Third Amended and Restated Bylaws of Concho Resources Inc., as amended March 27, 2017 (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K on March 28, 2017, and incorporated herein by reference).
4.1		Specimen Common Stock Certificate (filed as Exhibit 4.1 to the Company's Annual Report on Form 10-K on February 22, 2013, and incorporated herein by reference).
4.2		Twelfth Supplemental Indenture, dated September 26, 2017, among Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on September 26, 2017, and incorporated herein by reference).
4.3		Thirteenth Supplemental Indenture, dated September 26, 2017, among Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.2 to the Company's Current Report on Form 8-K on September 26, 2017, and incorporated herein by reference).
4.4		Form of 3.750% Senior Notes due 2027 (included in Exhibit 4.1 to the Company's Current Report on Form 8-K filed on September 26, 2017, and incorporated herein by reference).
4.5		Form of 4.875% Senior Notes due 2047 (included in Exhibit 4.2 to the Company's Current Report on Form 8-K filed on September 26, 2017, and incorporated herein by reference).
31.1	(a)	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	(a)	

		Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	(b)	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	(b)	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS	(a)	XBRL Instance Document.
101.SCH	(a)	XBRL Schema Document.
101.CAL	(a)	XBRL Calculation Linkbase Document.
101.DEF	(a)	XBRL Definition Linkbase Document.
101.LAB	(a)	XBRL Labels Linkbase Document.
101.PRE	(a)	XBRL Presentation Linkbase Document.

(a) Filed herewith.

(b) Furnished herewith.

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.

CONCHO RESOURCES INC.

Date:	November 1, 2017	By	/s/ Timothy A. Leach
			Timothy A. Leach Chairman of the Board of Directors and Chief Executive Officer (Principal Executive Officer)
		By	/s/ Jack F. Harper
			Jack F. Harper President and Chief Financial Officer (Principal Financial Officer)
		By	/s/ Brenda R. Schroer
			Brenda R. Schroer Senior Vice President, Chief Accounting Officer and Treasurer (Principal Accounting Officer)