CONCHO RESOURCES INC
Form 10-K
February 20, 2019

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018

or

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

For the transition period from ____________________ to ____________________

Commission file number: 1-33615

Concho Resources Inc.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**76-0818600** (I.R.S. Employer Identification No.)
One Concho Center **600 West Illinois Avenue** **Midland, Texas** (Address of principal executive offices)	**79701** (Zip Code)

(432) 683-7443
(Registrant’s telephone number,
including area code)

Securities Registered Pursuant to
Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, $0.001 par value	**New York Stock Exchange**

Securities Registered Pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes No

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

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

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

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

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter:	$20,433,760,692
Number of shares of the registrant's common stock outstanding as of February 15, 2019:	200,594,232

Documents Incorporated by Reference:

Portions of the registrant's definitive proxy statement for its 2019 Annual Meeting of Stockholders, which will be filed with the United States Securities and Exchange Commission within 120 days of December 31, 2018, are incorporated by reference into Part III of this Form 10-K for the year ended December 31, 2018.

TABLE OF CONTENTS

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements and information contained in or incorporated by reference into this report that express a belief, expectation, or intention, or that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). These forward-looking statements include statements, projections and estimates concerning our future financial position, operations, performance, business strategy, oil and natural gas reserves, drilling program, capital expenditures, liquidity and capital resources, the timing and success of specific projects, outcomes and effects of litigation, claims, disputes and derivative activities. Forward-looking statements are generally accompanied by words such as “estimate,” “project,” “predict,” “believe,” “expect,” “anticipate,” “potential,” “could,” “may,” “foresee “will,” “goal” or other words that convey future events, expectations or possible outcomes. Forward-looking statements are not guarantees of performance. We have based these forward-looking statements on our current expectations and assumptions about future events and their potential effect on us. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. Actual results may differ materially from those implied or expressed by any forward-looking statements. These forward-looking statements speak only as of the date of this report, or if earlier, as of the date they were made. We disclaim any obligation to update or revise these statements unless required by law, whether as a result of new information, future events or otherwise, and we caution you not to rely on them unduly. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties relating to, among other matters, the risks discussed in “Item 1A. Risk Factors” in this report, as well as those factors summarized below:

- declines in, the sustained depression of, or increased volatility in the prices we receive for our oil and natural gas, or increases in the differential between index oil or natural gas prices and prices received;

- drilling, completion and operating risks, including our ability to efficiently execute large-scale project development as we could experience delays, curtailments and other adverse impacts associated with a high concentration of activity;

- the effects of government regulation, permitting and other legal requirements, including new legislation or regulation related to hydraulic fracturing, climate change or derivatives reform;

- disruptions to, capacity constraints in or other limitations on the pipeline systems that deliver our oil and natural gas and other processing and transportation considerations;

- risks related to ongoing expansion of our business, including the recruitment and retention of qualified personnel in the Permian Basin;

- competition in the oil and natural gas industry;

- risks related to the concentration of our operations in the Permian Basin of Southeast New Mexico and West Texas;

- the costs and availability of equipment, resources, services and qualified personnel required to perform our drilling, completion and operating activities;

- environmental hazards, such as uncontrollable flows of oil, natural gas, saltwater, well fluids, toxic gas or other pollution into the environment, including groundwater contamination;

- uncertainties about the estimated quantities of oil and natural gas reserves;

- risks associated with acquisitions such as increased expenses and integration efforts, failure to realize the expected benefits of the transaction and liabilities associated with acquired properties or businesses;

- evolving cybersecurity risks, such as those involving unauthorized access, denial-of-service attacks, malicious software, data privacy breaches by employees, insiders or others with authorized access, cyber or phishing-attacks, ransomware, malware, social engineering, physical breaches or other actions;

- the impact of current and potential changes to federal or state tax rules and regulations;

- potential financial losses or earnings reductions from our commodity price risk-management program;

- difficult and adverse conditions in the domestic and global capital and credit markets;

- the adequacy of our capital resources and liquidity including, but not limited to, access to additional borrowing capacity under our Credit Facility, as defined herein;

- the impact of potential changes in our credit ratings;

- uncertainties about our ability to successfully execute our business and financial plans and strategies;

- uncertainties about our ability to replace reserves and economically develop our current reserves;

- general economic and business conditions, either internationally or domestically; and

- uncertainty concerning our assumed or possible future results of operations.

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

PART I

Item 1. Business

General

Concho Resources Inc., a Delaware corporation ("Concho," the "Company," "we," "us" and "our") formed in February 2006, is an independent oil and natural gas company engaged in the acquisition, development, exploration and production of oil and natural gas properties. Our operations are primarily focused in the Permian Basin of Southeast New Mexico and West Texas. The Permian Basin is one of the most prolific oil and natural gas producing regions in the United States and is characterized by an extensive production history, long reserve life, multiple producing horizons and recovery potential. Concho's legacy in the Permian Basin provides us a deep understanding of operating and geological trends, and we are actively developing our resource base utilizing large-scale development projects, which include long-lateral wells and multi-well pad locations, throughout our operating areas. Our strategy remains focused on development and exploration activities on our multi-year project inventory, and pursuing acquisitions that meet our strategic and financial objectives.

Business and Properties

Our operations are focused in the Permian Basin, which underlies an area of Southeast New Mexico and West Texas approximately 250 miles wide and 300 miles long. Commercial accumulations of hydrocarbons occur in multiple stratigraphic horizons, at depths ranging from less than 1,000 feet to over 25,000 feet. At December 31, 2018, our 1,187 MMBoe total estimated proved reserves consisted of approximately 63 percent oil and 37 percent natural gas. We have assembled a multi-year inventory of horizontal development and exploration projects across our operating areas.

We have one operating segment and one reporting unit, which is oil and natural gas development, exploration and production. All of our operations are conducted in one geographic area of the United States.

On July 19, 2018, we completed the acquisition of RSP Permian, Inc. ("RSP") through an all-stock transaction (the "RSP Acquisition"). RSP was an independent oil and natural gas company engaged in the acquisition, exploration, development and production of oil and natural gas reserves in the Permian Basin.

The vast majority of RSP's acreage was located on large, contiguous acreage blocks in the core of the Midland Basin and the Delaware Basin. The acquisition added approximately 92,000 net acres to our asset portfolio.

Following the RSP Acquisition, we simplified our asset structure, changing from four operating areas to two – comprising the Midland Basin and the Delaware Basin, which includes our assets in the Northern Delaware Basin, Southern Delaware Basin and New Mexico Shelf.

The following table summarizes our drilling activity during the periods indicated:

	Years Ended December 31,		
	2018	**2017**	**2016**
Gross wells	428	311	249
Net wells	266	197	170
Percent of gross wells drilled horizontally	100%	100%	100%
Percent of gross wells:			
Productive	44%	61%	56%
Unsuccessful	0%	1%	-
Awaiting completion at year-end	56%	38%	44%
	100%	100%	100%

Summary of Operating Areas

The following is a summary of information regarding our operating areas:

	December 31, 2018					
Operating Areas	**Estimated Proved Reserves (MMBoe)**	**% Oil**	**% Proved Developed**	**Total Gross Acreage (in thousands)**	**Total Net Acreage (in thousands)**	**2018 Average Daily Production (MBoe per Day)**
Delaware Basin	674	61%	73%	644	434	181
Midland Basin	513	66%	64%	315	206	82
Total	1,187	63%	69%	959	640	263

Operating areas

Our operations are focused in the Delaware Basin and the Midland Basin, within the greater Permian Basin. In both areas, we are transitioning our development to large-scale manufacturing mode, which includes leveraging our experience and expertise to maximize resource recovery and program economics while optimizing well spacing, landing intervals, lateral length and completion techniques.

Delaware Basin. At December 31, 2018, we had estimated proved reserves in this area of 674 MMBoe, representing 57 percent of our total proved reserves. During the year ended December 31, 2018, we commenced drilling or participated in the drilling of 281 (171 net) wells in this area, and we completed 239 (136 net) wells that are producing.

The Delaware Basin is characterized by a thick, resource-rich hydrocarbon column that lends itself to multi-zone development. We leverage leading-edge horizontal drilling and completion technologies, utilizing multi-well pad sites and extended lateral lengths to develop multiple producing formations. Our current activity is focused primarily on the Avalon, Bone Spring and Wolfcamp formations, which generally range from 6,500 feet to 13,500 feet.

Midland Basin. At December 31, 2018, we had estimated proved reserves in this area of 513 MMBoe, representing 43 percent of our total proved reserves. During the year ended December 31, 2018, we commenced drilling or participated in the drilling of 147 (95 net) wells in this area, and we completed 111 (68 net) wells that are producing.

Our primary objectives in the Midland Basin area are the Spraberry and Wolfcamp formations, which generally range from 7,500 feet to 11,500 feet. We are developing these formations with horizontal drilling, utilizing multi-well pad sites and extended lateral development.

Drilling Activities

The following table sets forth information with respect to (i) wells drilled and completed during the periods indicated and (ii) wells drilled in a prior period but completed in the periods indicated. The information should not be considered indicative of future performance, nor should a correlation be assumed between the number of productive wells drilled, quantities of reserves found or economic value.

	Years Ended December 31,					
	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	114	80	96	76	95	76
Dry	-	-	1	1	-	-
Exploratory wells:						
Productive	236	124	209	112	131	83
Dry	1	1	3	3	1	1
Total wells:						
Productive	350	204	305	188	226	159
Dry (a)	1	1	4	4	1	1
Total	351	205	309	192	227	160

(a) The dry hole category includes 1 (1 net) well that was unsuccessful due to mechanical issues for the year ended December 31, 2018.

Present activities. The following table sets forth information about wells for which drilling was in-progress or are pending completion at December 31, 2018, which are not included in the above table:

	Drilling In-Progress		Pending Completion	
	Gross	Net	Gross	Net
Development and exploratory wells	85	62	165	108

4

Our Production, Prices and Expenses

The following table sets forth a summary of our production and operating data for the years ended December 31, 2018, 2017 and 2016. The actual historical data in this table excludes results from the RSP Acquisition for periods prior to July 19, 2018 and our acquisition of certain assets of 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 acquisitions or divestitures, the historical information presented below should not be interpreted as being indicative of future results.

	Years Ended December 31,		
	2018	**2017**	**2016**
Production and operating data:			
Net production volumes:			
Oil (MBbl)	61,251	43,472	33,840
Natural gas (MMcf)	208,326	161,089	127,481
Total (MBoe)	95,972	70,320	55,087
Average daily production volumes:			
Oil (Bbl)	167,811	119,101	92,459
Natural gas (Mcf)	570,756	441,340	348,309
Total (Boe)	262,937	192,658	150,511
Average prices per unit:			
Oil, without derivatives (Bbl)	$ 56.22	$ 48.13	$ 39.90
Oil, with derivatives (Bbl) (a)	$ 52.73	$ 49.93	$ 57.90
Natural gas, without derivatives (Mcf)	$ 3.40	$ 3.07	$ 2.23
Natural gas, with derivatives (Mcf) (a)	$ 3.37	$ 3.06	$ 2.36
Total, without derivatives (Boe)	$ 43.25	$ 36.78	$ 29.68
Total, with derivatives (Boe) (a)	$ 40.98	$ 37.88	$ 41.03
Operating costs and expenses per Boe: (b)			
Oil and natural gas production	$ 6.14	$ 5.80	$ 5.81
Production and ad valorem taxes	$ 3.19	$ 2.82	$ 2.38
Gathering, processing and transportation	$ 0.58	$ -	$ -
Depreciation, depletion and amortization	$ 15.41	$ 16.29	$ 21.19
General and administrative	$ 3.25	$ 3.46	$ 4.09

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

	Years Ended December 31,		
(in millions)	2018	2017	2016
Net cash receipts from (payments on) derivatives:			
Oil derivatives	$ (213)	$ 79	$ 609
Natural gas derivatives	(5)	-	16
Total	$ (218)	$ 79	$ 625

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.

(b) Per Boe amounts calculated using dollars and volumes rounded to thousands.

Productive Wells

The following table sets forth the number of productive oil and natural gas wells on our properties at December 31, 2018, 2017 and 2016. As of December 31, 2018, we did not have any wells with multiple completions. This table does not include wells in which we own a royalty interest only.

	Gross Productive Wells			**Net Productive Wells**		
	Oil	**Natural Gas**	**Total**	**Oil**	**Natural Gas**	**Total**
December 31, 2018						
Operating Areas:						
Delaware Basin	4,801	690	5,491	3,569	313	3,882
Midland Basin	3,770	13	3,783	2,437	4	2,441
Other	-	3	3	-	-	-
Total	8,571	706	9,277	6,006	317	6,323
December 31, 2017						
Operating Areas:						
Delaware Basin	4,801	586	5,387	3,469	274	3,743
Midland Basin	2,747	15	2,762	1,675	6	1,681
Other	-	3	3	-	-	-
Total	7,548	604	8,152	5,144	280	5,424
December 31, 2016						
Operating Areas:						
Delaware Basin	4,656	607	5,263	3,385	262	3,647
Midland Basin	2,577	15	2,592	1,298	5	1,303
Other	-	3	3	-	-	-
Total	7,233	625	7,858	4,683	267	4,950

Marketing Arrangements

General. We market our oil and natural gas in accordance with standard energy industry practices. The marketing effort endeavors to obtain the combined highest netback and most secure market available at that time. In addition, marketing supports our operations group as it relates to the planning and preparation of future development activity so that available markets can be assessed and secured. This planning also involves the coordination of access to the physical facilities necessary to connect forthcoming wells as timely and efficiently as possible.

Oil. We generally sell production at the lease to third-party purchasers. We generally do not transport, refine or process the oil we produce. Most of our Delaware Basin production in New Mexico is connected to the Alpha Crude Connector, LLC ("ACC") pipeline system. This production is then primarily purchased by five different purchasers.

Most of our Delaware Basin production in Texas is connected to one of five different gathering systems. One of these systems is a crude oil gathering and transportation system operated by a subsidiary of Oryx Southern Delaware Holdings, LLC ("Oryx"), an entity in which we own a 23.75 percent membership interest. A significant portion of our Midland Basin production is on one of seven different gathering systems. The remaining portion of our production is sold via truck transport. We sell our produced oil under contracts using market-based pricing, which is adjusted for differentials based upon delivery location and oil quality.

Natural Gas. We consider all natural gas gathering, treating and processing service providers in the areas of our production and evaluate market options to obtain the best price reasonably available given the necessary operating conditions. We sell the majority of our natural gas under individually negotiated natural gas purchase contracts using market-based pricing. The majority of our natural gas is subject to long-term agreements that generally extend five to ten years from the effective date of the subject contract.

The majority of our natural gas is casinghead gas, which is sold at the lease location under (i) percentage of proceeds processing contracts, (ii) fee-based contracts or (iii) a hybrid of percentage of proceeds and fee-based contracts. The purchaser gathers our casinghead natural gas in the field where it is produced and transports it via pipeline to natural gas processing plants where natural gas liquid products are extracted and sold by the processors. The portion of natural gas remaining after liquid extraction is residue gas, which is placed on residue pipeline systems downstream of the processing plant. Under our percentage of proceeds and hybrid percentage of proceeds and fee-based contracts, we receive a percentage of the value for the extracted liquids and the residue gas. Under our fee-based contracts, we receive natural gas liquids and residue gas value, less the fee component thereof, or are invoiced the fee component of the purchaser's service.

Our Principal Customers

We sell our oil and natural gas production principally to marketers and other purchasers that have access to pipeline facilities. In areas where there is no practical access to pipelines, oil is transported to storage facilities by trucks owned or otherwise arranged by the marketers or purchasers. Our marketing of oil and natural gas can be affected by factors beyond our control, the effects of which cannot be accurately predicted.

For 2018, revenues from oil and natural gas sales to Plains Marketing and Transportation, Inc. accounted for approximately 18 percent of our total operating revenues. While the loss of this purchaser may result in a temporary interruption in sales of, or a lower price for, our production, we believe that the loss of this purchaser would not have a material adverse effect on our operations, as there are alternative purchasers in our producing regions. See Note 13 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

Competition

The oil and natural gas industry in the areas in which we operate is highly competitive. We encounter strong competition from numerous parties, ranging generally from small independent producers to major integrated companies. We primarily encounter significant competition in acquiring properties. At higher commodity prices, we also face competition in contracting for drilling, pressure pumping and workover equipment and securing trained personnel. Many of these competitors have financial, technical and personnel resources substantially larger than ours. As a result, our competitors may be able to pay more for desirable properties, or to evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources will permit.

In addition to competition for drilling, pressure pumping and workover equipment, we are also affected by the availability of related equipment and materials. The oil and natural gas industry periodically experiences shortages of drilling and workover rigs, equipment, pipe, materials and personnel, which can delay drilling, workover and exploration activities and cause significant price increases. We are unable to predict the timing or duration of any such shortages.

Working Capital

Based on current market conditions, we have maintained a stable liquidity position. Our principal source of liquidity is available borrowing capacity under our credit facility, as amended and restated (the "Credit Facility"). At December 31, 2018, we had $242 million of debt outstanding and $1,756 million of unused commitments under our Credit Facility, net of letters of credit. Our primary needs for cash are development, exploration and acquisitions of oil and natural gas assets, payment of contractual obligations and working capital obligations. However, additional borrowings under our Credit Facility or the issuance of additional debt securities will require a greater portion of our cash flow from operations to be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flow to fund working capital, capital expenditures and acquisitions.

Applicable Laws and Regulations

Regulation of Production

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and the plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Environmental, Health and Safety Matters

General*.* Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment. These laws, rules and regulations may, among other things:

- require the acquisition of various permits before drilling commences;

- require notice to stakeholders of proposed and ongoing operations;

- require the installation of expensive pollution control equipment;

- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas drilling and production and saltwater disposal activities;

- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, or otherwise restrict or prohibit activities that could impact the environment, including water resources; and

- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

These laws, rules and regulations may also restrict the production rate of oil and natural gas below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Violations and liabilities with respect to these laws and regulations could result in significant administrative, civil or criminal penalties, remedial clean-ups, natural resource damages, permit modifications or revocations, operational interruptions or shutdowns and other liabilities. The costs of remedying such conditions may be significant, and remediation obligations could adversely affect our financial condition, results of operations and leasehold acreage. Additionally, environmental laws and regulations are revised frequently, and any changes, including changes in implementation or interpretation, that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

The following is a summary of some of the existing laws, rules and regulations to which our business is subject.

Waste handling*.* The Resource Conservation and Recovery Act (“RCRA”) and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Pursuant to regulatory guidance issued by the federal Environmental Protection Agency (the “EPA”), the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of oil or natural

Competition

gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. For example, in December 2016, the EPA and certain environmental organizations entered into a consent decree to address EPA's alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and natural gas wastes from regulation as hazardous wastes under RCRA. The consent decree requires EPA to propose a rulemaking no later than March 15, 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and natural gas wastes or to sign a determination that revision of the regulations is not necessary. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position. Also, in the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes if such wastes have hazardous characteristics.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response Compensation and Liability Act ("CERCLA"), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current or former owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to strict, joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. Each state, including Texas, also has environmental cleanup laws analogous to CERCLA.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose storage, treatment and disposal of hazardous substances, wastes or hydrocarbons were not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property, or perform remedial operations to prevent future contamination.

Water discharges. The federal Water Pollution Control Act (the "Clean Water Act") and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters, including dredge and fill activities in regulated wetlands, is prohibited, except in accordance with the terms of a permit issued by the EPA, or, in some circumstances, the U.S. Army Corps of Engineers (the “Corps”), or an analogous state agency. In addition, spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. Further, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

In September 2015, new EPA and Corps rules to revise the definition of “waters of the United States” (“WOTUS”) for all Clean Water Act programs, thereby defining the scope of the EPA’s and the Corps’ jurisdiction, became effective. To the extent the rule expands the scope of jurisdiction of the Clean Water Act, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. The rule has been challenged in court on the grounds that it unlawfully expands the reach of Clean Water Act programs, and implementation of the rule has been stayed pending resolution of the court challenge. In response to this decision, the EPA and the Corps resumed nationwide use of the agencies’ prior regulations defining the term “waters of the United States.” Those regulations will be implemented as they were prior to the effective date of the new WOTUS rule. In January 2017, the U.S. Supreme Court accepted review of the WOTUS rule to determine whether jurisdiction to hear challenges to the rule rests with the federal district or appellate courts. In June 2017, the EPA and the Corps proposed a rule that would initiate the first step in a two-step process intended to review and revise the definition of “waters of the United States.” Under the proposal, the first step would be to rescind the May 2015 final rule and put back into effect the narrower language defining “waters of the United States” under the Clean Water Act that existed prior to the rule. The second step would be a notice-and-comment rule-making in which the agencies will conduct a substantive reevaluation of the definition of “waters of the United States.” In January 2018, the Supreme Court ruled that the WOTUS rule must first be reviewed in federal district courts, remanding the case at issue to the district level and putting the status of the Sixth Circuit’s stay of the new rule into question. Citing uncertainty caused by litigation, the EPA subsequently announced a two year stay of the application of the rule as it undertakes its own review of the rule. Federal district court decisions have preserved the stay of the 2015 Clean Water Rule in Texas and New Mexico, which remain subject to pre-2015 WOTUS regulations. Litigation surrounding this rule is ongoing. More recently, on December 11, 2018, the EPA and the Corps released a proposal to revise the 2015 Clean Water Rule so as to narrow the regulatory definition of waters of the U.S., with a

60-day comment period to follow. The scope of the jurisdictional reach of the Clean Water Act will likely remain uncertain for several years.

Safe Drinking Water Act. Our oil and natural gas exploration and production operations generate produced water, drilling muds, and other waste streams, some of which may be disposed via injection in underground wells situated in non-producing subsurface formations. The drilling and operation of these injection wells are regulated by the federal Safe Drinking Water Act (the "SDWA"). The Underground Injection Well Program under the SDWA requires that we obtain permits from the EPA or delegated state agencies for our disposal wells, establishes minimum standards for injection well operations, restricts the types and quantities of fluids that may be injected and prohibits the migration of fluid containing any contaminants into underground sources of drinking water. Any leakage from the subsurface portions of the injection wells may cause degradation of freshwater, potentially resulting in cancellation of operations of a well, imposition of fines and penalties from governmental agencies, incurrence of expenditures for remediation of affected resources, and imposition of liability by landowners or other parties claiming damages for alternative water supplies, property damages, and personal injuries. Any changes in the laws or regulations or the inability to obtain permits for new injection wells in the future may affect our ability to dispose of produced waters and would ultimately increase the cost of our operations, which costs could be significant. For example, in 2014 the Railroad Commission of Texas (the "RRC") adopted additional permit rules for injection wells to address seismic activity concerns within the state. Among other things, the rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells, and allow the RRC to modify, suspend, or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. Furthermore, in response to recent seismic events near underground injection wells used for the disposal of oil and natural gas-related wastewaters, federal and some state agencies have begun investigating whether such wells have caused increased seismic activity, and some states have shut down or imposed moratoria on the use of such injection wells. For example, in 2016, the Oklahoma Corporation Commission issued various orders and regulations applicable to disposal operations in specific counties in Oklahoma. These rules require that disposal well operators, among other things, conduct additional mechanical integrity testing, make sure that their wells are not injecting wastes into targeted formations, and/or reduce the volumes of wastes disposed in such wells. If new regulatory initiatives are implemented that restrict or prohibit the use of underground injection wells in areas where we rely upon the use of such wells in our operations, our costs to operate may significantly increase, and our ability to continue production may be delayed or limited, which could have a material adverse effect on our results of operations and financial position.

Air emissions. The federal Clean Air Act (the "CAA"), and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. These and other laws and regulations may increase the costs of compliance for some facilities where we operate. Obtaining or renewing permits also has the potential to delay the development of our projects. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources.

For example, in October 2015, the EPA lowered the National Ambient Air Quality Standard (“NAAQS”) for ozone from 75 to 70 parts per billion. By July 2018, the EPA finished issuing area designations with respect to ground-level ozone for U.S. counties as either "attainment/unclassifiable" or "unclassifiable." Reclassification of areas of state implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant. In addition, in June 2016, the EPA finalized rules under the CAA regarding criteria for aggregating multiple sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities (such as tank batteries), on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements, which in turn could result in operational delays or require us to install costly pollution control equipment. In a separate rulemaking in June 2016, the EPA finalized new air emission control requirements for emissions of methane from certain equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities. The final rule package includes first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions, and also imposes leak detection and repair requirements on operators. In addition, the rule package extends existing volatile organic compound (“VOC”) standards under the EPA’s Subpart OOOO of the New Source Performance Standards to include previously unregulated equipment within the oil and natural gas source category. However, in June 2017, the EPA proposed a two year stay of the fugitive emissions monitoring requirements, pneumatic pump standards, and closed vent system certification requirements in the 2016 New Source Performance Standards rule for the oil and gas industry while it reconsiders these aspects of the rule. On September 11, 2018, the EPA proposed targeted improvements to the rule, including amendments to the rule’s fugitive emissions monitoring requirements, and expects to “significantly reduce” the regulatory burden of the rule in doing so. The U.S. Bureau of Land Management (the “BLM”) finalized similar rules in November 2016 that limit methane emissions from new and existing oil and natural gas operations on federal lands through limitations on the venting and flaring of gas, as well as enhanced leak detection and repair requirements. The BLM adopted final rules in January 2017. Operators generally had one year from the January 2017 effective date to come into compliance with the rule’s requirements. However, in December 2017, the BLM temporarily suspended or delayed certain of these requirements set forth in its Venting and Flaring Rule until January 2019, and in September 2018 the BLM proposed a revised rule which scaled back the waste-prevention requirements of the 2016 rule. Environmental groups sued in federal district court a day later to challenge the legality of aspects of the revised rule, and the outcome of this litigation is currently uncertain. These air emission rules have the potential to increase our compliance costs.

Climate change. In response to findings that emissions of carbon dioxide, methane and other "greenhouse gases" ("GHGs") present an endangerment to public health and the environment, the EPA has issued regulations to restrict emissions of GHGs under existing provisions of the CAA. These regulations include limits on tailpipe emissions from motor vehicles and preconstruction and operating permit requirements for certain large stationary sources. The EPA has also adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, as well as certain onshore oil and natural gas production facilities, on an annual basis, including GHG emissions resulting from the completion and workover operations of hydraulically fractured oil wells. Recent federal regulatory action with respect to climate change has focused on methane emissions. As noted above, both the EPA and the BLM finalized rules in 2016 that limit methane emissions from upstream oil and natural gas exploration and production operations. Increased regulation of methane and other GHGs have the potential to result in increased compliance costs and, consequently, adversely affect our operations.

On August 3, 2015, the EPA also issued new regulations limiting carbon dioxide emissions from existing power generation facilities. Under these regulations, nationwide carbon dioxide emissions would be reduced by approximately 30 percent from 2005 levels by 2030 with a flexible interim goal. Several industry groups and states challenged the rule. On February 9, 2016, the U.S. Supreme Court stayed the implementation of this rule pending judicial review. On March 28, 2017, President Trump signed an Executive Order directing the EPA to review the regulations, and on April 4, 2017, the EPA announced that it was reviewing the 2015 carbon dioxide regulations. On April 28, 2017, the U.S. Court of Appeals for the District of Columbia stayed the litigation pending the current administration's review. That stay was extended for another 60 days on August 8, 2017. On October 10, 2017, the EPA initiated the formal rulemaking process to repeal the regulations. In August 2018, the EPA proposed the Affordable Clean Energy rule as a replacement to the 2015 regulations. The EPA's proposals are subject to public comment and likely legal challenge, and as such, we cannot predict at this time what impact the rulemaking will have on the demand for oil and natural gas production and our operations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce emissions of GHGs in recent years. In the absence of Congressional action, many states have established rules aimed at reducing GHG emissions, including GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and natural gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal. In addition, in 2015, the United States participated in the United Nations Conference on Climate Change, which led to the creation of the Paris Agreement. The Paris Agreement requires countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals, every five years beginning in 2020. However, in June 2017, President Trump announced that the United States plans to withdraw from the Paris Agreement and seek negotiations either to reenter the Paris Agreement on different terms or establish a new framework agreement. The Paris

Agreement provides for a four-year exit process beginning in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process or the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances, or to comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Reduced demand for the oil and natural gas that we produce could also have the effect of lowering the value of our reserves. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. It should also be noted that some scientists have concluded that increasing concentrations of GHGs in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations. Finally, increasing attention to the risks of climate change has resulted in an increased possibility of lawsuits brought by public and private entities against oil and gas companies in connection with their GHG emissions. Should we be targeted by any such litigation, we may incur liability, which, to the extent that societal pressures or political or other factors are involved, could be imposed without regard to our causation of or contribution to the asserted damage, or to other mitigating factors.

Hydraulic fracturing*.* Hydraulic fracturing is an important and common practice that is used to stimulate production of oil and/or natural gas from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing as part of our operations. The process is typically regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel and issued guidance in February 2014 governing such activities. The EPA has also issued final regulations under the CAA establishing performance standards, including standards for the capture of VOCs and methane released during hydraulic fracturing (although the EPA has temporarily suspended or delayed compliance with certain of these standards as they undergo an administrative review); an advanced notice of proposed rulemaking under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing; and final rules in

June 2016 that prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. Moreover, in March 2015, the BLM issued a final rule that imposes requirements on hydraulic fracturing activities on federal and Indian lands, including new requirements relating to public disclosure, wellbore integrity and handling of flowback water. However, the BLM lacked authority to promulgate the rule. While that decision was on appeal, the BLM rescinded this rule in December 2017. In January 2018, the state of California and a coalition of environmental groups filed a lawsuits in the Northern District of California to challenge the BLM's rescission of the 2015 rule. This litigation is ongoing and future implementation of the rule is uncertain at this time.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. For example, New Mexico and Texas have adopted hydraulic fracturing fluid disclosure requirements, and the RRC has also adopted rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. In addition, local governments have also taken steps to regulate hydraulic fracturing, including imposing restrictions or moratoria on oil and natural gas activities occurring within their boundaries. If new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under some circumstances, noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. Since the report did not find a direct link between hydraulic fracturing itself and contamination of groundwater resources, this years-long study report does not appear to provide any basis for further regulation of hydraulic fracturing at the federal level.

We do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations; however, we believe our well control, general liability and excess liability insurance policies may cover third-party claims related to hydraulic fracturing operations and associated legal expenses in accordance with, and subject to, the terms of such policies. If new laws or regulations significantly restrict hydraulic fracturing activities or impose burdens on new permitting or operating requirements, our ability to utilize hydraulic fracturing may be curtailed, and this may in turn reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Operations on Federal Lands. We currently operate on federal lands under the jurisdiction of the BLM. Permitting for oil and natural gas activities on federal lands can take significantly longer than the state permitting process. Delays in obtaining permits necessary can disrupt our operations and have an adverse effect on our business. As noted above, in November 2016, the BLM finalized rules that restrict methane emissions from oil and natural gas activities on federal lands by limiting venting and flaring of natural gas from wells and other equipment. The final rule also requires operators to pay royalties to the BLM on flared gas from wells already connected to gas capture infrastructure, and allows the agency to set royalty rates at or above 12.5 percent of the value of production. These rules could result in increased compliance costs for our operations, which in turn could have an adverse effect on our business and results of operations.

Endangered species. The federal Endangered Species Act (the “ESA”) and analogous state laws regulate activities that could have an adverse effect on threatened or endangered species. Some of our drilling operations are conducted in areas where protected species are known to exist. In these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts to protected species, and we may be prohibited from conducting drilling operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to drilling activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. The presence of a protected species in areas where we perform drilling activities could impair our ability to timely complete drilling and developmental operations and could adversely affect our future production from those areas. The designation of previously unprotected species as threatened or endangered in areas where we or our oil and natural gas exploration and production customers operate could cause us or our customers to incur increased costs arising from species protection measures and could result in delays or limitations in our customers’ performance of operations, which could reduce demand for our midstream services.

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act (“NEPA”). NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay or even halt development of some of our oil and natural gas projects.

OSHA and other laws and regulations. We are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. Also, pursuant to OSHA, the Occupational Safety and Health Administration has established a variety of standards relating to workplace exposure to hazardous substances and employee health and safety.

We are not aware of any existing environmental issues, claims or regulations that will require us to incur material capital expenditures during 2019, and we did not incur material capital expenditures relating to environmental issues, claims or regulations during 2018. However, we cannot assure that the passage or application of more stringent laws or regulations or the application of existing laws in the future will not require us to incur material capital expenditures or have a material adverse effect on our financial position or results of operations.

Our Employees

Our corporate headquarters are located at One Concho Center, 600 West Illinois Avenue, Midland, Texas 79701. We also maintain various field offices in Texas and New Mexico. At December 31, 2018, we had 1,503 employees, 569 of whom were employed in field operations. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be good.

Available Information

We file or furnish annual, quarterly and current reports, proxy statements and other documents with the U.S. Securities and Exchange Commission (the "SEC") under the Exchange Act. The public can obtain any documents that we file with the SEC at *www.sec.gov*. We also make available free of charge through our website, *www.concho.com*, our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

Non-GAAP Financial Measures and Reconciliations

Reconciliation of Standardized Measure to PV-10

PV-10 is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the standardized measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the standardized measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas assets. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas assets. PV-10, however, is not a substitute for the standardized measure of discounted future net cash flows. Our PV-10 measure and the standardized measure of discounted future net cash flows do not purport to present the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of the GAAP standardized measure of discounted future net cash flows to PV-10 (non-GAAP) at December 31, 2018, 2017 and 2016:

	December 31,		
(in millions)	**2018**	**2017**	**2016**
Standardized measure of discounted future net cash flows	$ 15,555	$ 7,478	$ 4,190
Present value of future income taxes discounted at 10%	2,392	1,001	652
PV-10	$ 17,947	$ 8,479	$ 4,842

Reconciliation of Net Income (Loss) to Adjusted EBITDAX

Adjusted EBITDAX (as defined below) is presented herein and reconciled from the GAAP measure of net income (loss) because of its wide acceptance by the investment community as a financial indicator.

We define Adjusted EBITDAX as net income (loss), plus (1) exploration and abandonments, (2) depreciation, depletion and amortization, (3) accretion of discount on asset retirement obligations, (4) impairments of long-lived assets, (5) non-cash stock-based compensation, (6) (gain) loss on derivatives, (7) net cash receipts from (payments on) derivatives, (8) (gain) loss on disposition of assets, net, (9) interest expense, (10) loss on extinguishment of debt, (11) gain on equity method investment distribution, (12) RSP transaction costs and (13) federal and state income tax expense (benefit). Adjusted EBITDAX is not a measure of net income (loss) or cash flows as determined by GAAP.

Our Adjusted EBITDAX measure provides additional information that may be used to better understand our operations. Adjusted EBITDAX is one of several metrics that we use as a supplemental financial measurement in the evaluation of our business and should not be considered as an alternative to, or more meaningful than, net income (loss) as an indicator of operating performance. Certain items excluded from Adjusted EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic cost of depreciable and depletable assets. Adjusted EBITDAX, as used by us, may not be comparable to similarly titled measures reported by other companies. We believe that Adjusted EBITDAX is a widely followed measure of operating performance and is one of many metrics used by our management team and by other users of our consolidated financial statements. For example, Adjusted EBITDAX can be used to assess our operating performance and return on capital in comparison to other independent exploration and production companies without regard to financial or capital structure and to assess the financial performance of our assets and our Company without regard to capital structure or historical cost basis.

The following table provides a reconciliation of the GAAP measure of net income (loss) to Adjusted EBITDAX (non-GAAP) for the periods indicated:

	Years Ended December 31,				
(in millions)	**2018**	**2017**	**2016**	**2015**	**2014**
Net income (loss)	$ 2,286	$ 956	$ (1,462)	$ 66	$ 538
Exploration and abandonments	65	59	77	59	285
Depreciation, depletion and amortization	1,478	1,146	1,167	1,223	980
	10	8	7	8	7

Accretion of discount on asset retirement obligations					
Impairments of long-lived assets	-	-	1,525	61	447
Non-cash stock-based compensation	82	60	59	63	47
(Gain) loss on derivatives	(832)	126	369	(700)	(891)
Net cash receipts from (payments on) derivatives	(218)	79	625	633	72
(Gain) loss on disposition of assets, net	(800)	(678)	(118)	54	9
Interest expense	149	146	204	215	217
Loss on extinguishment of debt	-	66	56	-	4
Gain on equity method investment distribution	(103)	-	-	-	-
RSP transaction costs	32	-	-	-	-
Income tax expense (benefit)	603	(75)	(876)	31	318
Adjusted EBITDAX	$ 2,752	$ 1,893	$ 1,633	$ 1,713	$ 2,033

Item 1A. Risk Factors

You should consider carefully the following risk factors together with all of the other information included in this report and other reports filed with the SEC before investing in our securities. If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected. In that case, the trading price of our securities could decline and you could lose all or part of your investment.

Risks Related to Our Business

Oil and natural gas are volatile. A decline in oil and natural gas prices could adversely affect our financial position, financial results, cash flow, access to capital and ability to grow.

Our future financial condition, revenues, results of operations, rate of growth and the carrying value of our oil and natural gas properties depend primarily upon the prices we receive for our oil and natural gas production and the prices prevailing from time to time for oil and natural gas. Oil and natural gas prices historically have been volatile and are likely to continue to be volatile in the future, especially given current geopolitical conditions. This price volatility also affects the amount of cash flow we have available for capital expenditures and our ability to borrow money or raise additional capital. The prices and levels of production for oil and natural gas are subject to a variety of factors beyond our control, including:

- the overall global demand for oil and natural gas;

- the overall global supply of oil and natural gas;

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

- the U.S. economy,

- weather conditions, and

- liquefied natural gas (“LNG”) deliveries to and exports from the United States;
- economic conditions worldwide;
- the level of global crude oil, crude oil products and LNG inventories;
- volatility and trading patterns in the commodity-futures markets;
- 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;
- 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;
- the effect of energy conservation efforts;
- additional restrictions on the exploration, development and production of oil, natural gas and natural gas liquids so as to materially reduce emissions of carbon dioxide and methane GHGs;
- political and economic events that directly or indirectly impact the relative strength or weakness of the U.S. dollar, on which oil prices are benchmarked globally, against foreign currencies;

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

- the cost and availability of products and personnel needed for us to produce oil and natural gas, including rigs, crews, sand, water and water disposal;

- 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; and
- the price, availability and acceptance of alternative fuels.

Furthermore, oil and natural gas prices continued to be volatile in 2018. For example, NYMEX oil prices in 2018 ranged from a high of $76.41 to a low of $42.53 per Bbl and the NYMEX natural gas prices in 2018 ranged from a high of $4.84 to a low of $2.55 per MMBtu. Further, the NYMEX oil prices and NYMEX natural gas prices reached highs of $55.59 per Bbl and $3.59 per MMBtu, respectively, during the period from January 1, 2019 to February 15, 2019.

Declines in oil and natural gas prices would not only reduce our revenue, but could also reduce the amount of oil and natural gas that we can produce economically. This in turn would lower the amount of oil and natural gas reserves we could recognize and, as a result, could have a material adverse effect on our financial condition and results of operations. If the oil and natural gas industry experiences significant price declines for a sustained period, we may, among other things, be unable to maintain or increase our borrowing capacity, repay current or future indebtedness or obtain additional capital on attractive terms, all of which can adversely affect the value of our securities.

Approximately 31 percent of our total estimated proved reserves at December 31, 2018 were undeveloped, and those reserves may not ultimately be developed.

At December 31, 2018, approximately 31 percent of our total estimated proved reserves were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling. Our reserves data assumes that we can and will make these expenditures and conduct these operations successfully. These assumptions, however, may not prove correct. Our reserve report at December 31, 2018 includes estimates of total future development costs over the next five years associated with our proved undeveloped reserves of approximately $3.3 billion. If we choose not to spend the capital to develop these reserves, or if we are not otherwise able to successfully develop these reserves, we will be required to write-off these reserves. In addition, under the SEC’s reserve rules, because proved undeveloped reserves may be recognized only if they relate to wells planned to be drilled within five years of the date of their initial recognition, we may be required to write-off any proved undeveloped reserves that are not developed within this five-year timeframe. For example, as of December 31, 2018, we wrote-off approximately 77 MMBoe of proved undeveloped reserves primarily because we no longer expect to develop these reserves within five years of the date of their initial recognition.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that could cause our costs to increase or production volumes to decrease, which would reduce our

cash flows.

Our future financial condition and results of operations depend on the success of our exploration and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil and natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Our cost of drilling, completing, equipping and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical or less economical than forecasted. Further, many factors may curtail, delay or cancel drilling, including the following:

- shortages of or delays in obtaining equipment and qualified personnel or in obtaining sand or water for hydraulic fracturing activities;
- delays imposed by or resulting from compliance with regulatory and contractual requirements;
- reductions in oil and natural gas prices;
- delays and costs of drilling wells on lands subject to complex development terms and circumstances;
- oil or natural gas gathering, transportation and processing availability restrictions or limitations;
- pressure or irregularities in geological formations;
- equipment failures or accidents;
- adverse weather conditions and natural disasters;
- political events, public protests, civil disturbances, terrorist acts or cyber attacks;

- environmental hazards, such as natural gas leaks, oil and produced water spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well

17

stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;

- surface access restrictions;
- failure to obtain regulatory and third-party approvals;
- actions by third-party operators of our properties;
- loss of title or other title related issues;
- limitations in the market for oil and natural gas; and
- limited availability of financing at acceptable terms.

The occurrence of one or more of these factors could result in a partial or total loss of our investment in a particular property, as well as significant liabilities. Moreover, certain of these events could result in environmental pollution and impact to third parties, including persons living in proximity to our operations, our employees and employees of our contractors, leading to possible injuries, death or significant damage to property and natural resources.

In addition, the results of our exploratory drilling in new or emerging plays are more uncertain than drilling results in areas that are developed and have established production. Since new or emerging plays and new formations have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. As a result, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

Multi-well pad drilling and project development may result in volatility in our operating results.

We utilize multi-well pad drilling and project development where practical. Project development may involve more than one multi-well pad being drilled and completed at one time in a relatively confined area. Wells drilled on a pad or in a project may not be brought into production until all wells on the pad or project are drilled and completed. Problems affecting one pad or a single well could adversely affect production from all of the wells on the pad or in the entire project. As a result, multi-well pad drilling and project development can cause delays in the scheduled commencement of production, or interruptions in ongoing production. These delays or interruptions may cause declines or volatility in our operating results due to timing as well as declines in oil and natural gas prices. Further, any delay, reduction or curtailment of our development and producing operations, due to operational delays caused by multi-well pad drilling or project development, or otherwise, could result in the loss of acreage through lease expirations.

Additionally, infrastructure expansion, including more complex facilities and takeaway capacity, could become challenging in project development areas. Managing capital expenditures for infrastructure expansion could cause economic constraints when considering design capacity.

Prolonged decreases in our drilling program may require us to pay certain non-use fees or impact our ability to comply with certain contractual requirements.

Oil prices declined substantially during the second half of 2014 and continued to decline through 2016, but began to recover in 2017 and through most of 2018, although pricing remains volatile. In the event that oil prices decline for a sustained period, we may experience significant decreases in drilling activity. Due to the nature of our drilling programs and the oil and natural gas industry in general, we are a party to certain agreements that require us to meet various contractual obligations or require us to utilize a certain amount of goods or services, including, but not limited to, water commitments, throughput volume commitments, power commitments and drilling commitments. In the event that oil and natural gas prices decrease, and as a result continue to reduce the demand for drilling and production, this could lead to a decrease in our drilling activity and production levels, which could, in turn, require us to pay for unutilized goods or services or impact our ability to meet these contractual obligations, including drilling commitments that may result in lease expirations if unmet.

We may incur losses as a result of title defects in our oil and natural gas properties.

It is our practice to initially conduct only a cursory title review of the oil and natural gas properties on which we do not have proved reserves. To the extent title opinions or other investigations prior to our commencement of drilling operations reflect defects affecting such properties, we are typically responsible for curing any such defects at our expense. Additionally, the discovery of any such defects could delay or prohibit the commencement of drilling operations on the affected properties. These impacts and other potential losses resulting from title defects in our oil and natural gas properties could have a material adverse effect on our business, financial condition and results of operations.

18

Our operations are substantially dependent on the availability of water and our ability to dispose of produced water gathered from drilling and production activities. Restrictions on our ability to obtain water or dispose of produced water may have an adverse effect on our financial condition, results of operations and cash flows.

Water is an essential component of both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local land owners and other sources for use in our operations. Over the past few years, extreme drought conditions persisted in Southeast New Mexico and West Texas. Although conditions have improved, we cannot guarantee what conditions may occur in the future. Severe drought conditions can result in local water districts taking steps to restrict the use of water subject to their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil and natural gas, which could have an adverse effect on our financial condition, results of operations and cash flows.

In addition, we must dispose of the fluids produced from oil and natural gas production operations, including produced water, which we do directly or through the use of third party vendors. The legal requirements related to the disposal of produced water into a non-producing geologic formation by means of underground injection wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities. One such concern arises from recent seismic events near underground disposal wells that are used for the disposal by injection of produced water resulting from oil and natural gas activities. In March 2016, the United States Geological Survey identified Texas and Colorado as being among the states with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and natural gas extraction. In response to concerns regarding induced seismicity, regulators in some states have imposed, or are considering imposing, additional requirements in the permitting of produced water disposal wells to assess any relationship between seismicity and the use of such wells. For example, in Texas, the RRC adopted new rules governing the permitting or re-permitting of wells used to dispose of produced water and other fluids resulting from the production of oil and natural gas in order to address these seismic activity concerns within the state. Among other things, these rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells and allow the state to modify, suspend or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. States may issue orders to temporarily shut down or to curtail the injection depth of existing wells in the vicinity of seismic events.

Another consequence of seismic events may be lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells by us or by commercial disposal well vendors whom we may use from time to time to dispose of produced water. Increased regulation and attention given to induced seismicity could also lead to greater opposition, including litigation to limit or prohibit oil and natural gas activities utilizing injection wells for produced water disposal.

Any one or more of these developments may result in us or our vendors having to limit disposal well volumes, disposal rates and pressures or locations, or require us or our vendors to shut down or curtail the injection into disposal wells, which events could have a material adverse effect on our business, financial condition and results of operations.

Federal, state and local legislation and regulatory initiatives relating to hydraulic fracturing, as well as governmental reviews of such activities, could result in increased costs and additional operating restrictions or delays and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. We routinely utilize hydraulic fracturing techniques in many of our drilling and completion programs. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and natural gas commissions. However, the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the SDWA's Underground Injection Control Program and issued guidance in February 2014, governing such activities. The EPA has also issued: final regulations under the CAA establishing performance standards, including standards for the capture of VOCs and methane released during hydraulic fracturing (although the EPA has temporarily suspended or delayed compliance with certain of these standards as they undergo an administrative review); an advanced notice of proposed rulemaking under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing; and final rules in June 2016 to prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. Moreover, in March 2015, the BLM issued a final rule that imposes requirements on hydraulic fracturing activities on federal and Indian lands, including new requirements relating to public disclosure, wellbore integrity and handling of flowback water. However, the BLM lacked authority to promulgate the rule. While that decision was on appeal, the BLM rescinded this rule in December 2017. In January 2018, the state of California and a coalition of environmental groups filed a lawsuit in the Northern District of California to challenge the BLM's rescission of the 2015 rule. This litigation is ongoing and future implementation of the rule is uncertain at this time.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. For example, New Mexico and Texas have adopted hydraulic fracturing fluid disclosure requirements, and the RRC has also adopted rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. In addition, local governments have also taken steps to regulate hydraulic fracturing, including imposing restrictions or moratoria on oil and natural gas activities occurring within their boundaries. If new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources under some circumstances, noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. Since the report did not find a direct link between hydraulic fracturing itself and contamination of groundwater resources, this years-long study report does not appear to provide any basis for further regulation of hydraulic fracturing at the federal level.

If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, our fracturing activities could become subject to additional permitting requirements and could also result in permitting delays and potential cost increases. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Climate change legislation, regulations restricting emissions of “greenhouse gases” or legal or other action taken by public or private entities related to climate change could result in increased operating costs and reduced demand for the oil and natural gas that we produce.

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment, the EPA has issued regulations to restrict emissions of GHGs under existing provisions of the CAA. These regulations include limits on tailpipe emissions from motor vehicles and preconstruction and operating permit requirements for certain large stationary sources. The EPA has also adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, as well as certain onshore oil and natural gas production facilities, on an annual basis, including GHG emissions resulting from the completion and workover operations of hydraulically fractured oil wells. Recent federal regulatory action with respect to climate change has focused on methane emissions. For example, in June 2016, the EPA finalized new air emission controls for emissions of methane from certain equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities. The final rule package includes first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions, and also imposes leak detection and repair requirements on operators. However, in June 2017, the EPA proposed a two year stay of fugitive emissions monitoring requirements, pneumatic pump standards, and closed vent system certification requirements in the 2016 rule while it reconsiders these aspects of the rule. Additionally, on September 11, 2018, the EPA proposed targeted improvements to the 2016 rule, including amendments to the rule's fugitive emissions monitoring requirements, and expects to "significantly reduce" the regulatory burden of the rule in doing so. The BLM finalized similar rules in November 2016 that limit methane emissions from new and existing oil and natural gas operations on federal lands through limitations on the venting and flaring of gas, as well as enhanced leak detection and repair requirements but then finalized a revised rule in 2018 which scaled back the waste prevention requirements of the 2016 rule. Environmental groups have sued in federal district court to challenge the legality of aspects of the revised rule, and the outcome of this litigation is currently uncertain. These methane emission rules have the potential to increase our compliance costs.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce emissions of GHGs in recent years. In the absence of Congressional action, many states have established rules aimed at reducing GHG emissions, including GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and natural gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal. In the future, the United States may also choose to adhere to international agreements targeting GHG reductions.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or to comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Reduced demand for the oil and natural gas that we produce could also have the effect of lowering the value of our reserves. It should also be noted that some scientists have concluded that increasing concentrations of GHGs in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations. In addition, there have also been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital. Finally, increasing attention to the risks of climate change has resulted in an increased possibility of lawsuits or investigations brought by public and private entities against oil and natural gas companies in connection with their GHG emissions. Should we be targeted by any such litigation or investigations, we may incur liability, which, to the extent that societal pressures or political or other factors are involved, could be imposed without regard to the causation of or contribution to the asserted damage, or to other mitigating factors. The ultimate impact of GHG emissions-related agreements, legislation and measures on our company’s financial performance is highly uncertain because the Company is unable to predict with certainty, for a multitude of individual jurisdictions, the outcome of political decision-making processes and the variables and tradeoffs that inevitably occur in connection with such processes.

Estimates of proved reserves and future net cash flows are not precise. The actual quantities of our proved reserves and our future net cash flows may prove to be lower than estimated.

Numerous uncertainties exist in estimating quantities of proved reserves and future net cash flows therefrom. Our estimates of proved reserves and related future net cash flows are based on various assumptions, which may ultimately prove to be inaccurate.

Petroleum engineering is a subjective process of estimating accumulations of oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including the following:

- historical production from the area compared with production from other producing areas;

- the assumed effects of regulations by governmental agencies;

- the quality, quantity and interpretation of available relevant data;

- assumptions concerning future commodity prices; and

- assumptions concerning future operating costs, severance and ad valorem taxes, development costs and workover and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items, or other items not identified below, may differ materially from those assumed in estimating reserves:

- the quantities of oil and natural gas that are ultimately recovered;

- the production and operating costs incurred;

- the amount and timing of future development expenditures; and

- future commodity prices.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same data. Our actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material.

As required by the SEC, the estimated discounted future net cash flows from proved reserves are based on the average previous twelve months first-of-month prices preceding the date of the estimate and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as:

- the amount and timing of actual production;

- levels of future capital spending;

- increases or decreases in the supply of or demand for oil and natural gas; and
- changes in governmental regulations or taxation.

Accordingly, estimates included herein of future net cash flows may be materially different from the future net cash flows that are ultimately received. Therefore, the estimates of discounted future net cash flows in this report should not be construed as accurate estimates of the current market value of our proved reserves.

Our business requires substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a decline in our oil and natural gas reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the acquisition, exploration and development of oil and natural gas reserves. At December 31, 2018, we had approximately $242 million of debt outstanding under our Credit Facility (and total debt at December 31, 2018 of $4.2 billion), and we had approximately $1.8 billion of unused commitments under our Credit Facility. Expenditures for acquisition, exploration and development of oil and natural gas properties are the primary use of our capital resources. We incurred approximately $10.4 billion in acquisition, exploration and development costs during the year ended December 31, 2018, of which approximately $7.6 billion related to the RSP Acquisition. In October 2018, our board of directors approved our 2019 capital budget, excluding acquisitions, of up to approximately $3.8 billion. With current commodity prices, we expect to spend between $2.8 billion and $3.0 billion on drilling and completion activity. We plan to spend approximately $3.3 billion over the next five years on future development costs associated with proved undeveloped reserves.

We intend to finance our future capital expenditures, other than significant acquisitions, through cash flow from operations and, if necessary, through borrowings under our Credit Facility. However, our cash flow from operations and access to capital are subject to a number of variables, including:

- the volume of oil and natural gas we are able to produce from existing wells;

- our ability to transport our oil and natural gas to market;

- the prices at which our commodities are sold;

- the costs of producing oil and natural gas;

- global credit and securities markets;
- the ability and willingness of lenders and investors to provide capital and the cost of the capital;
- our ability to acquire, locate and produce new reserves;
- the impact of potential changes in our credit ratings; and
- our proved reserves.

We may not generate expected cash flows and may have limited ability to obtain the capital necessary to sustain our operations at current or anticipated levels. A decline in cash flow from operations or our financing needs may require us to revise our capital program or alter or increase our capitalization substantially through the issuance of debt or equity securities. The issuance of additional equity securities could have a dilutive effect on the value of our common stock. Additional borrowings under our Credit Facility or the issuance of additional debt securities will require that a greater portion of our cash flow from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flow to fund working capital, capital expenditures and acquisitions. In addition, our Credit Facility imposes certain limitations on our ability to incur additional indebtedness other than indebtedness under our Credit Facility. If we desire to issue additional debt securities other than as expressly permitted under our Credit Facility, we will be required to seek the consent of the lenders in accordance with the requirements of our Credit Facility, which consent may be withheld by the lenders at their discretion. Additional financing also may not be available on acceptable terms or at all. In the event additional capital resources are unavailable, we may curtail drilling, development and other activities or be forced to sell some of our assets on an untimely or unfavorable basis.

The failure to obtain additional financing could result in a curtailment of our operations relating to the development of our undeveloped acreage or the curtailment of acquisitions that may be favorable to us, which in turn could lead to a decline in our oil and natural gas reserves, and could adversely affect our production, revenues and results of operations.

A decline in general economic, business or industry conditions could have a material adverse effect on our results of operations.

A global economic downturn, particularly with respect to the U.S. economy or the oil and natural gas industry, and global financial and credit market disruptions reduce the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide, which can result in a slowdown in economic activity. Reduced worldwide demand for energy often results in lower commodity prices, which will reduce our cash flows and may affect our borrowing ability. If the economic climate in the United States or abroad deteriorates, we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our reserves as existing reserves are depleted. Lower commodity prices may also reduce the amount of oil and natural gas that we can produce economically, which could ultimately decrease our net revenue and profitability. In addition, reduced worldwide demand for securities issued by oil and natural gas companies or depressed trading prices of the debt and equity securities of oil and natural gas companies generally may depress the market value of our securities or make it more difficult for us to raise capital.

Recently enacted legislation will affect our tax position; however, certain federal income tax deductions currently available with respect to oil and natural gas exploration and development may be eliminated. Additional state taxes on oil and natural gas extraction may be imposed, as a result of future legislation.

In December 2017, Congress enacted the budget reconciliation act commonly referred to as the Tax Cuts and Jobs Act (“TCJA”). The law made significant changes to U.S. federal income tax laws, including reducing the corporate income tax rate from 35 percent to 21 percent, repealing the corporate alternative minimum tax (“AMT”), partially limiting the deductibility of interest expense and net operating losses (“NOLs”), eliminating the deduction for certain U.S. production activities and allowing the immediate deduction of certain new investments in lieu of depreciation expense over time. Although we have evaluated the TCJA and recorded adjustments as required in our financial statements, many aspects of the TCJA are unclear and may not be clarified for some time. We will continue to monitor any new administrative guidance or tax law interpretation.

In recent years, U.S. lawmakers have proposed certain significant changes to U.S. tax laws applicable to oil and natural gas companies. These changes include, but are not limited to: (i) the elimination of current deductions for intangible drilling and development costs; (ii) the repeal of the percentage depletion allowance for oil and natural gas properties; and (iii) an extension of the amortization period for certain geological and geophysical expenditures. Although these changes were not included in the TCJA, it is unclear whether any such changes will be enacted or if enacted, when such changes could be effective. If such proposed changes were to be enacted, as well as any similar changes in state law, it could eliminate or postpone certain tax deductions that are currently available to us with respect to oil and natural gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

Additionally, future legislation could be enacted that increases the taxes or fees imposed on oil and natural gas extraction. Any such legislation could result in increased operating costs and/or reduced consumer demand for petroleum products, which in turn could affect the prices we receive for our oil and natural gas.

Our ability to use our existing net operating loss carryforwards or other tax attributes could be limited.

At December 31, 2018, we had approximately $2.2 billion of federal NOL carryforwards available to offset against future taxable income. Of these NOL carryforwards, $1.5 billion were generated prior to the effective date of new limitations on utilization of NOLs imposed by the TCJA and are allowable as a deduction against 100 percent of taxable income in future years but will begin to expire in the tax year 2034. The estimated current year NOL of approximately $675 million is subject to an 80 percent limitation but has an indefinite carryforward life. Included in our $2.2 billion of federal NOL carryforwards is approximately $516 million net NOLs that we acquired as part of the RSP Acquisition. These acquired tax attributes are subject to an annual limitation under Section 382 of the Internal Revenue Code of 1986, as amended ("Section 382"). However, based on the annual limitation amount, the NOLs and credits are expected to be fully utilizable by the tax year 2022.

Utilization of any NOL depends on many factors, including our ability to generate future taxable income, which cannot be assured. In addition, Section 382 generally imposes an annual limitation on the amount of NOLs that may be used to offset taxable income when a corporation has undergone an "ownership change" (as determined under Section 382). An ownership change generally occurs if one or more stockholders (or groups of stockholders) who are each deemed to own at least five percent of our stock change their ownership by more than 50 percentage points over their lowest ownership percentage within a rolling three-year period. In the event that an ownership change has occurred, or were to occur, utilization of our NOLs would be subject to an annual limitation under Section 382, determined by multiplying the value of our equity at the time of the ownership change by the applicable long-term tax-exempt rate as defined in Section 382, and potentially increased for certain gains recognized within five years after the ownership change if we have a net built-in gain in our assets at the time of the ownership change. Any unused annual limitation may be carried over to later years. We do not believe that an ownership change has occurred as a result of our recent equity offerings or our issuance of shares in connection with various acquisitions. As such, Section 382 is not expected to limit our ability to utilize our NOL carryforward or any other tax attribute at December 31, 2018. Future ownership changes or future regulatory changes could limit our ability to utilize our NOLs. To the extent we are not able to offset our future income with our NOLs, this could adversely affect our operating results and cash flows once we attain profitability.

We have substantial indebtedness and may incur substantially more debt. Higher levels of indebtedness make us more vulnerable to economic downturns and adverse developments in our business.

We had approximately $4.2 billion of outstanding aggregate principal indebtedness at December 31, 2018. At December 31, 2018, commitments from our bank group were $2.0 billion, of which $1.8 billion was unused commitments. We continue to review our existing indebtedness, and we may seek to repay, refinance, repurchase, redeem, exchange or otherwise terminate our indebtedness. If we do seek to refinance our existing indebtedness, there can be no guarantee that we would be able to execute the refinancing on favorable terms or at all.

As a result of our indebtedness, we use a portion of our cash flow to pay interest, which reduces the amount we have available to fund our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate. Our indebtedness under our Credit Facility is at a variable interest rate, and so a rise in interest rates will generate greater interest expense.

We may incur substantially more debt in the future. Our Credit Facility and the indentures governing our senior notes contain restrictions on our incurrence of additional indebtedness. These restrictions, however, are subject to a number of qualifications and exceptions, and under certain circumstances, we could incur substantial additional indebtedness in compliance with these restrictions. Moreover, these restrictions do not prevent us from incurring obligations that do not constitute indebtedness under the indentures.

Any increase in our level of indebtedness could have adverse effects on our financial condition and results of operations, including:

- imposing additional cash requirements on us in order to support interest payments, which reduces the amount we have available to fund our operations and other business activities;

- increasing the risk that we may default on our debt obligations;

- increasing our vulnerability to adverse changes in general economic and industry conditions, economic downturns and adverse developments in our business;

- limiting our ability to sell assets, engage in strategic transactions or obtain additional financing for working capital, capital expenditures, general corporate and other purposes;

- limiting our flexibility in planning for or reacting to changes in our business and the industry in which we operate; and

- increasing our exposure to a rise in interest rates, which will generate greater interest expense.

Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance, which is affected by general economic conditions and financial, business and other factors, many of which are out of our control.

If we are unable to comply with the restrictions and covenants in the agreements governing our indebtedness, there could be a default under the terms of these agreements, which could result in an acceleration of payment of funds that we have borrowed.

Our ability to meet our debt obligations and other expenses will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors, many of which we are unable to control. If our cash flow is not sufficient to service our debt, we may be required to refinance debt, sell assets or sell additional equity on terms that we may not find attractive if it may be done at all. If we are unable to generate sufficient cash flow and are otherwise unable to obtain funds necessary to meet required payments of principal, premium, if any, and interest, if any, on our indebtedness, or if we otherwise fail to comply with the various covenants, including financial and operating covenants, in the agreements governing our indebtedness, we could be in default under the terms of the agreements governing such indebtedness. In the event of such default:

- the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest;

- the lenders under our Credit Facility could elect to terminate their commitments thereunder and cease making further loans; and

- we could be forced into bankruptcy or liquidation.

If our operating performance declines, we may in the future need to obtain waivers under our Credit Facility to avoid being in default. If we breach our covenants under our Credit Facility cannot obtain a waiver from the required lenders, we would be in default under our Credit Facility, the lenders could exercise their rights, as described above, and we could be forced into bankruptcy or liquidation.

A downgrade in our credit rating could negatively impact our cost of and ability to access capital.

24

We receive debt credit ratings from S&P Global Ratings ("S&P"), Moody's Investors Service, Inc. ("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.

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. In September 2017, we elected to enter into an Investment Grade Period under our Credit Facility, as defined in Note 10 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data," which had the effect of releasing all collateral formerly securing our Credit Facility. 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 our 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 report, no additional changes in our credit ratings have occurred; however, we cannot be assured that our credit ratings will not be downgraded in the future.

Our operations expose us to significant costs and liabilities with respect to environmental and operational safety matters.

We may incur significant delays, costs and liabilities as a result of environmental, occupational health and safety requirements applicable to our oil and natural gas exploration, development and production, and related saltwater disposal activities. These delays, costs and liabilities could arise under a wide range of federal, state and local laws and regulations relating to protection of the environment, occupational health and safety, including regulations and enforcement policies that have tended to become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations.

Strict as well as joint and several liability for a variety of environmental costs may be imposed on us under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. Costs stemming from environmental remediation obligations could be significant and adversely affect our financial condition and results of operations. New laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. No assurance can be given that continued compliance with existing or future environmental laws and regulations will not result in a curtailment of production or processing activities or result in a material increase in the costs of production, development, exploration or processing operations. If we are not able to recover the resulting costs through insurance or increased revenues, our production, revenues and results of operations could be adversely affected.

Our producing properties are concentrated in the Permian Basin of Southeast New Mexico and West Texas, making us vulnerable to risks associated with operating in one major geographic area. In addition, substantially all of our proved reserves are attributable to this area.

Our producing properties are geographically concentrated in the Permian Basin of Southeast New Mexico and West Texas. At December 31, 2018, substantially all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we are exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, including current pipeline capacity constraints in the Permian Basin, market limitations, severe weather events, water shortages or other drought related conditions or interruption of the processing or transportation of oil or natural gas.

In addition to the geographic concentration of our producing properties described above, at December 31, 2018, approximately: (i) 57 percent of our proved reserves were attributable to the Delaware Basin that primarily targets the Avalon, Bone Spring and Wolfcamp formations; and (iii) 43 percent of our proved reserves were attributable to the Midland Basin that primarily targets the Spraberry and Wolfcamp formations. This concentration of assets exposes us to additional risks, such as changes in field-wide rules and regulations that could cause us to permanently or temporarily shut-in all of our wells within a field.

We periodically assess our unproved oil and natural gas properties for impairment and could be required to recognize non-cash charges to earnings of future periods.

At December 31, 2018, we carried unproved property costs of $6.7 billion. GAAP requires periodic assessment of these costs on a project-by-project basis. Our assessment considers:

- future drilling and exploration plans;
- results of exploration activities;
- commodity price outlooks;
- planned future sales; and
- expiration of all or a portion of the projects, contracts and permits relevant to such projects.

Based on our assessments, we may determine that we are unable to fully recover the cost invested in each project, and we will recognize non-cash charges to earnings in future periods if such determination is made. For the years ended December 31, 2018 and 2017, we recorded approximately $35 million and $27 million, respectively, of leasehold abandonments primarily related to expiring acreage and acreage where we had no future plans to drill, which is included in exploration and abandonments expense in our consolidated statements of operations.

We periodically evaluate our goodwill for impairment and could be required to recognize non-cash charges in the earnings of future periods.

At December 31, 2018, we had goodwill of $2.2 billion. Goodwill is assessed for impairment as of July 1 of each year or whenever circumstances indicate that the carrying value of our business may be impaired. If the book value of our reporting unit exceeds the estimated fair value of the reporting unit, an impairment charge will occur, which would negatively impact our results of operations and net worth.

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 our 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. We did not incur an impairment charge in 2018 and 2017. We recorded impairment charges of $1.5 billion in 2016.

Our commodity price risk management program may cause us to forego additional future profits or result in us making cash payments to our counterparties.

To reduce our exposure to changes in the prices of 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. Commodity price risk management arrangements expose us to the risk of financial loss and may limit our ability to benefit from increases in commodity prices in some circumstances, including the following:

- market prices may exceed the prices which we are contracted to receive, resulting in our need to make significant cash payments to our counterparties;

- there may be a change in the expected differential between the underlying price in a commodity price risk management agreement and actual prices received; or

- the counterparty to a commodity price risk management contract may default on its contractual obligations to us.

Our commodity price risk management activities could have the effect of reducing our net income and the value of our securities. At December 31, 2018, we had a net derivative asset of approximately $695 million. An average increase in the commodity price of $5.00 per barrel of oil and $0.50 per MMBtu of natural gas from the commodity price at December 31, 2018 would have resulted in a decrease in our net asset of approximately $406 million. We may continue to incur significant

26

gains or losses in the future from our commodity price risk management activities to the extent market prices increase or decrease and our derivatives contracts remain in place.

Our identified inventory of drilling locations and recompletion opportunities are scheduled over several future years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

We have identified and scheduled the drilling of certain locations as an estimation of our future multi-year development activities on our existing acreage. These identified locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including those described elsewhere in these risk factors. Because of these and other potential uncertainties, we may never drill the potential locations we have identified or produce oil or natural gas from these or any other potential locations. As such, our actual development activities may materially differ from those presently identified, which could adversely affect our production, reserves, revenues and results of operations.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our cash flow, our ability to raise capital and the value of our securities.

Unless we conduct successful development and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and therefore our cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. The value of our securities and our ability to raise capital will be adversely impacted if we are not able to replace our reserves that are depleted by production or replace our declining production with new production. We may not be able to develop, exploit, find or acquire sufficient additional reserves or replace our current and future production.

The Standardized Measure and PV-10 of our estimated reserves are not accurate estimates of the current fair value of our estimated proved oil and natural gas reserves.

Standardized Measure is a reporting convention that provides a common basis for comparing oil and natural gas companies subject to the rules and regulations of the SEC. Our non-GAAP financial measure, PV-10, is a similar reporting convention that we have disclosed in this report. Both measures require the use of operating and development costs prevailing as of the date of computation. Consequently, they will not reflect the prices ordinarily received or that will be received for oil and natural gas production because of varying market conditions, nor may it reflect the actual costs that will be required to produce or develop the oil and natural gas properties. Accordingly, estimates included herein of future net cash flows may be materially different from the future net cash flows that are ultimately received. In addition, the 10 percent discount factor, which is required by the rules and regulations of the SEC to be used in calculating discounted future net cash flows for reporting purposes, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our company or the oil and natural gas industry in general. Therefore, Standardized Measure and PV-10 included in this report should not be construed as accurate estimates of the current fair value of our proved reserves.

Our reserve estimates and our computation of future net cash flows at December 31, 2018 are based on SEC pricing of (i) $62.04 per Bbl WTI posted oil price and (ii) $3.10 per MMBtu Henry Hub spot natural gas price, adjusted for location and quality by property. The SEC pricing for reserves as of December 31, 2018 is higher than the NYMEX oil price of $55.59 per Bbl at February 15, 2019 and higher than the NYMEX natural gas price of $2.63 per MMBtu at February 15, 2019. If average oil prices were $5.00 per barrel lower than the average price we used, our PV-10 at December 31, 2018 would have decreased from $17.9 billion to $16.3 billion. If average natural gas prices were $0.50 per MMBtu lower than the average price we used, our PV-10 at December 31, 2018 would have decreased from $17.9 billion to $17.2 billion. Any adjustments to the estimates of proved reserves or decreases in the price of our commodities may decrease the value of our securities.

We may be unable to make attractive acquisitions or successfully integrate acquired companies or assets, and any inability to do so may disrupt our business and hinder our ability to grow.

One aspect of our business strategy calls for acquisitions of businesses or assets that complement or expand our current business. We may not be able to identify attractive acquisition opportunities, including acreage trades. Even if we do identify attractive candidates, pursuing such acquisitions may be distracting to management and costly to the Company. We may not be able to complete the acquisition of them or do so on commercially acceptable terms.

In addition, our Credit Facility and the indentures governing our senior notes impose certain limitations on our ability to enter into mergers or business combination transactions. Our Credit Facility and the indentures governing our senior notes also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses or assets. If we desire to engage in an acquisition that is otherwise prohibited by our Credit Facility or the indentures governing our senior notes, we will be required to seek the consent of our lenders or the holders of the senior notes in accordance with the requirements of our Credit Facility or the indentures, which consent may be withheld by the lenders under our Credit Facility or such holders of senior notes at their sole discretion.

If we acquire another business or assets, we could have difficulty integrating its operations, systems, management and other personnel and technology with our own. These difficulties could disrupt our ongoing business, distract our management and employees, increase our expenses and adversely affect our results of operations. In addition, we may incur additional debt or issue additional equity to pay for any future acquisitions, subject to the limitations described above.

Any acquisition we complete is subject to substantial risks that could adversely affect our business, including the risk that our acquisitions may prove to be worth less than what we paid because of uncertainties in evaluating recoverable reserves and could expose us to potentially significant liabilities.

We obtained a significant portion of our current reserve base through acquisitions of producing properties and undeveloped acreage. We expect that acquisitions, including acreage trades, will continue to contribute to our future growth. In connection with these and potential future acquisitions, we are often only able to perform limited due diligence. The success of any acquisition involves potential risks, including among other things:

- the inability to estimate accurately the costs to develop the reserves, recoverable volumes of reserves, rates of future production and future net cash flows attainable from the reserves;

- the assumption of unknown liabilities, including environmental liabilities, and losses or costs for which we are not indemnified or for which the indemnity we receive is inadequate;

- the effect on our liquidity or financial leverage of using available cash or debt to finance acquisitions;

- the diversion of management’s attention from other business concerns; and

- an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets.

Successful acquisitions of oil and natural gas properties require an assessment of a number of factors, including estimates of recoverable reserves, the timing of recovering reserves, exploration potential, future commodity prices, operating costs and potential environmental, regulatory and other liabilities. Such assessments are inexact, and we cannot make these assessments with a high degree of accuracy. In connection with our assessments, we perform a review of the acquired properties that we believe to be generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise.

There may be threatened, contemplated, asserted or other claims against the acquired assets related to environmental, title, regulatory, tax, contract, litigation or other matters of which we are unaware, which could materially and adversely affect our production, revenues and results of operations. We are sometimes able to obtain contractual indemnification for preclosing liabilities, including environmental liabilities, but we generally acquire interests in properties on an “as is” basis with limited remedies for breaches of representations and warranties. In addition, even when we are able to obtain such indemnification from the sellers, these indemnification obligations usually expire over time and expose us to potential unindemnified liabilities, which could materially adversely affect our production, revenues and results of operations.

Shortages of oilfield equipment, services and qualified personnel could delay our drilling program and increase the prices we pay to obtain such equipment, services and personnel.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with commodity prices, causing periodic labor shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other oilfield equipment as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher commodity prices generally stimulate demand and result in increased prices for drilling and workover rigs, crews and associated supplies, equipment and services. It is beyond our control and ability to predict whether these conditions will exist in the future and, if so, what their timing and duration will be. These types of shortages or price increases would decrease our profit margin, cash flow and operating results, or restrict our ability to drill the wells and conduct the operations which we currently have planned and budgeted or which we may plan in the future.

Our exploration and development drilling may not result in commercially productive reserves.

Drilling activities are subject to many risks, including the risk that commercially productive reservoirs will not be encountered. New wells that we drill may not be productive, or we may not recover all or any portion of our investment in such wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or natural gas is present or may be produced economically. Drilling for oil and natural gas often involves unprofitable results, not only from dry holes but also from wells that are productive but do not produce sufficient net reserves to return a profit at then

28

realized prices after deducting drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Further, our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including:

- unexpected drilling conditions;

- risks associated with drilling horizontal wells and extended lateral lengths, such as deviating from the desired drilling zone or not running casing or tools consistently through the wellbore, particularly as lateral lengths get longer;

- pressure or irregularities in formations;

- equipment failures or accidents;

- construction delays;

- fracture stimulation accidents or failures;

- adverse weather conditions;

- compliance with environmental and other governmental or contractual requirements; and

- increases in the cost of, or shortages or delays in the availability of, electricity, water, supplies, materials, drilling or workover rigs, equipment and services.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations. In addition, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities, including well stimulation and completion activities such as hydraulic fracturing, are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, saltwater, well fluids, toxic gas or other pollution into the environment, including groundwater contamination;
- abnormally pressured or structured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- blowouts, cratering, fires, explosions and ruptures of pipelines;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- damage to and destruction of property and equipment;
- damage to natural resources due to underground migration of hydraulic fracturing fluids;
- pollution and other environmental damage, including spillage or mishandling of recovered hydraulic fracturing fluids;

- regulatory investigations and penalties;
- loss of well location, acreage, expected production and related reserves;
- suspension or delay of our operations;
- substantial liability claims; and

- repair and remediation costs.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable, and we do not insure for business interruption of the loss of a well. The occurrence of an event that is not covered or not fully covered by insurance could have a material adverse effect on our production, revenues and results of operations.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil and natural gas and secure trained personnel.

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Some of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, those companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost and other challenges to attract and retain qualified personnel may increase substantially in the future. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital. Our failure to acquire properties, market oil and natural gas, secure trained personnel and adequately compensate personnel could have a material adverse effect on our production, revenues and results of operations.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

Market conditions or the unavailability of satisfactory oil and natural gas processing or transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas, the proximity of reserves to pipelines and storage facilities, gathering systems and other transportation, processing, fractionation, refining and export facilities, competition for such facilities and the inability of such facilities to gather, transport or process our production due to shutdowns or curtailments arising from mechanical, operational or weather related matters, including hurricanes and other severe weather conditions. Our ability to market our production depends in substantial part on the availability and capacity of gathering, storage and transportation systems, pipelines and processing facilities owned and operated by third parties. Throughout 2018, concerns emerged that Permian oil supply would exceed pipeline capacity. Our ability to market our production may be impacted if such constraints continue or become worse in the future. Our failure to obtain such services on acceptable terms or the failure of counterparties to perform under certain of our transportation or marketing arrangements could have a material adverse effect on our business, financial condition and results of operations. We may be required to shut in or otherwise curtail production from wells due to lack of a market or inadequacy or unavailability of oil or natural gas pipeline or gathering, storage, transportation or processing capacity and fractionation, refining or export facilities. If that were to occur, then we would be unable to realize revenue from those wells until suitable arrangements were made to market our production.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, timing, manner or feasibility of conducting our operations or that may subject us to fines or penalties for any failure to comply.

Our oil and natural gas exploration, development and production, and related saltwater disposal operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state, local and governmental authorities. We may incur substantial costs and experience delays in order to maintain compliance with these existing laws and regulations. If we fail to comply with the existing laws and regulations, we may incur additional costs, including fines and penalties, in order to come back into compliance. In addition, our costs of compliance may increase or our operations may be otherwise adversely affected if existing laws and regulations are revised or reinterpreted or if the government agencies responsible for enforcing certain existing laws and regulations applicable to us change their priorities or policies, or if new laws and regulations become applicable to our operations. These and other costs could have a material adverse effect on our production, revenues and results of operations.

The implementation of derivatives legislation adopted by Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, including us, which participate in that market. This legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Act”), became law on July 21, 2010 and requires the Commodity Futures Trading Commission (the “CFTC”) and the SEC to promulgate rules and regulations implementing the Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented, and it is not possible at this time to predict when this will be accomplished.

In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents; however this initial position limits rule was vacated by the U.S. District Court for the District of Columbia in September 2012. The CFTC has subsequently issued proposals for new rules that would place position limits on certain core futures contracts and equivalent swap contracts for or linked to certain physical commodities, subject to certain exceptions for bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps subject to mandatory clearing and the associated rules also will require us, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or take steps to qualify for an exemption to such requirements. The CFTC has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing. Although we expect to qualify for the end-user exception from the mandatory clearing requirements for swaps entered to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. If our swaps do not qualify for the commercial end-user exception from mandatory clearing, or if the cost of entering into uncleared swaps becomes prohibitive, we may be required to clear such transactions or our ability to hedge may be impacted. The ultimate effect of the rules and any additional regulations on our business is uncertain at this time.

In addition, certain banking regulators and the CFTC have adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to be exempt from such requirements for the mandatory exchange of margin for uncleared swaps, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. Further, if we do not qualify for an exemption and are required to post collateral for our swaps, it could reduce our liquidity and cash available for capital expenditures and our ability to manage commodity price volatility and the volatility in cash flows.

The full impact of the Act and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. When fully implemented, the Act and any new regulations could increase the operational and transactional cost of derivatives contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize and restructure our existing derivatives contracts, impact commodity prices and affect the number and/or creditworthiness of available counterparties. If we reduce our use of derivatives as a result of the Act and regulations implementing the Act, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

The loss of our chief executive officer or other key personnel could negatively impact our ability to execute our business strategy.

We depend, and will continue to depend in the foreseeable future, on the services of our chief executive officer, Timothy A. Leach, and other officers and key employees who have extensive experience and expertise in evaluating and analyzing producing oil and natural gas properties and drilling prospects, maximizing production from oil and natural gas properties, marketing oil and natural gas production, and developing and executing acquisition, financing and hedging strategies. Our ability to hire and retain our officers and key employees is important to our continued success and growth. The unexpected loss of the services of one or more of these individuals could negatively impact our ability to execute our business strategy.

Because we do not operate and therefore control the development of certain of the properties in which we own interests, we may not be able to produce economic quantities of oil and natural gas in a timely manner.

At December 31, 2018, approximately 6 percent of our proved reserves were attributable to properties for which we were not the operator. As a result, the success and timing of drilling and development activities on properties operated by others depend upon a number of factors that are beyond our control, including:

- the nature and timing of drilling and operational activities controlled by others;
- the timing and amount of the operators' capital expenditures;
- the operators' expertise and financial resources;
- the approval of other participants in such properties; and
- the selection and application of suitable technology.

If drilling and development activities are not conducted on these properties or are not conducted as we expect, we may be unable to increase our production or offset normal production declines or we will be required to write-off the reserves attributable to such properties, which may adversely affect our production, revenues and results of operations.

We do not control certain of the entities in which we own equity interests.

Certain of the entities in which we own equity interests are managed by their respective governing bodies. As a result, our ability to influence decisions with respect to the operation of such entities varies depending on the amount of control we exercise under the applicable governing agreement, including with respect to cash distributions, capital calls, capital expenditures and the incurrence of additional indebtedness.

A terrorist or cyber attack or armed conflict could harm our business by decreasing our revenues and increasing our costs.

Terrorist activities, anti-terrorist efforts, cyber attacks and other armed conflicts involving the United States may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur or escalate, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on demand for our production and causing a reduction in our revenue. Oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if significant infrastructure or facilities used for the production, transportation, processing or marketing of oil and natural gas production are destroyed or damaged. Additionally, as an oil and natural gas producer, we constantly face various cybersecurity threats, including threats to gain unauthorized access to sensitive information or to render data or systems unusable, and there can be no assurance that our implementation of various procedures and controls to monitor and mitigate security threats will be sufficient to prevent security breaches from occurring. Costs for insurance, recovery, remediation, potential litigation and other security measures may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

Our reliance on information technology, including those hosted by third parties, exposes us to cyber security risks that could affect our business, financial condition or reputation and increase compliance challenges.

We rely extensively on information technology systems, including internet sites, computer software, data hosting facilities and other hardware and platforms, some of which are hosted by third parties, to assist in conducting our business. Our information technology systems, as well as those of third parties we use in our operations, may be vulnerable to a variety of evolving cybersecurity risks, such as those involving unauthorized access, denial-of-service attacks, malicious software, data privacy breaches by employees, insiders or others with authorized access, cyber or phishing-attacks, ransomware, malware, social engineering, physical breaches or other actions. These cybersecurity threat actors are becoming more sophisticated and coordinated in their attempts to access the company's information technology systems and data, including the information technology systems of cloud providers and third parties with which the company conducts business.

Although we have implemented information technology controls and systems that are designed to protect information and mitigate the risk of data loss and other cybersecurity risks, such measures cannot entirely eliminate cybersecurity threats, and the enhanced controls we have installed may be breached. If our information technology systems cease to function properly or our cybersecurity is breached, we could suffer disruptions to our normal operations which may include drilling, completion, production and corporate functions. A cyber attack involving our information systems and related infrastructure, or that of our business associates, could negatively impact our operations in a variety of ways, including, but not limited to, the following:

- Unauthorized access to seismic data, reserves information, strategic information, or other sensitive or proprietary information could have a negative impact on our ability to compete for oil and natural gas resources;

- Data corruption, communication interruption, or other operational disruption during drilling activities could result in failure to reach the intended target or a drilling incident;

- Data corruption or operational disruptions of production-related infrastructure could result in a loss of production, or accidental discharge;

- A cyber attack on a vendor or service provider could result in supply chain disruptions which could delay or halt our major development projects;

- A cyber attack on third-party gathering, pipeline, or rail transportation systems could delay or prevent us from transporting and marketing our production, resulting in a loss of revenues;

- A cyber attack involving commodities exchanges or financial institutions could slow or halt commodities trading, thus preventing us from marketing our production or engaging in hedging activities, resulting in a loss of revenues;

32

- A cyber attack which halts activities at a power generation facility or refinery using natural gas as feed stock could have a significant impact on the natural gas market, resulting in reduced demand for our production, lower natural gas prices, and reduced revenues;

- A cyber attack on a communications network or power grid could cause operational disruption resulting in loss of revenues;

- A cyber attack on our automated and surveillance systems could cause a loss in production and potential environmental hazards;

- A deliberate corruption of our financial or operating data could result in events of non-compliance which could then lead to regulatory fines or penalties; and

- A cyber attack resulting in the loss or disclosure of, or damage to, our or any of our customer's or supplier's data or confidential information could harm our business by damaging our reputation, subjecting us to potential financial or legal liability, and requiring us to incur significant costs, including costs to repair or restore our systems and data or to take other remedial steps.

All of the above could negatively impact our operational and financial results. Additionally, certain cyber incidents, such as surveillance, may remain undetected for an extended period. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities. Additionally, the growth of cyber attacks has resulted in evolving legal and compliance matters which impose significant costs that are likely to increase over time.

Risks Related to Our Common Stock

Our certificate of incorporation, our bylaws and Delaware law contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Our certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our certificate of incorporation, our bylaws and Delaware law could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- the organization of our board of directors as a classified board, which allows no more than approximately one-third of our directors to be elected each year;

- stockholders cannot remove directors from our board of directors except for cause and then only by the holders of not less than 66 2/3 percent of the voting power of all outstanding voting stock;

- the prohibition of stockholder action by written consent; and

- limitations on the ability of our stockholders to call special meetings and establish advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders.

The payment of dividends will be at the discretion of our board of directors.

While the Company declared a quarterly dividend of $0.125 per share in the first quarter of 2019 and intends to continue to pay a dividend in the future, the payment and amount of future dividend payments, if any, are subject to declaration by our board of directors. Such payments will depend on various factors, including actual results of operations, liquidity and financial condition, net cash provided by operating activities, restrictions imposed by applicable law, our taxable income, our operating expenses and other factors our board of directors deems relevant. Covenants contained in our Credit Agreement and the indentures governing our senior notes could limit the payment of dividends. The Company is under no obligation to make dividend payments on our common stock and may cease such payments at any time in the future.

The availability of shares for sale in the future could reduce the market price of our common stock.

In the future, we may acquire interests in other companies by using a combination of cash and our common stock or just our common stock. We may also issue securities to raise cash for acquisitions. We may also issue securities convertible into, or exchangeable for, or that represent the right to receive, our common stock. Any of these events may dilute your ownership interest in our Company, reduce our earnings per share and have an adverse impact on the price of our common stock.

In addition, sales of a substantial amount of our common stock in the public market, or the perception that these sales may occur, could reduce the market price of our common stock. This could also impair our ability to raise additional capital through the sale of our securities.

Item 1B. Unresolved Staff Comments

There are no unresolved staff comments.

Item 2. Properties

Our Oil and Natural Gas Reserves

The estimates of our proved reserves at December 31, 2018, all of which were located in the United States, were based on evaluations prepared by the independent petroleum engineering firms of Cawley, Gillespie & Associates, Inc. (“CGA”) and Netherland, Sewell & Associates, Inc. (“NSAI”) (collectively, our “external engineers”). Reserves were estimated in accordance with guidelines established by the SEC and the Financial Accounting Standards Board (the “FASB”).

Internal controls. Our proved reserves are estimated at the property level by external engineers and compiled for reporting purposes by our corporate reservoir engineering staff. We maintain our internal evaluations of our reserves in a secure reserve engineering database. The corporate reservoir engineering staff interact with our internal staff of petroleum engineers, geoscience professionals and land professionals in each of our operating areas and with accounting and marketing employees to obtain the necessary data for the reserves estimation process. Reserves are reviewed and approved internally by members of our senior management and the health, safety, environment and reserves committee, a committee of our board of directors.

Our internal professional staff works closely with our external engineers to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. All of the reserve information maintained in our secure reserve engineering database is provided to the external engineers. In addition, other pertinent data is provided such as seismic information, geologic maps, well logs, production tests, material balance calculations, well performance data, operating procedures and relevant economic criteria. We make available all information requested, including our pertinent personnel, to the external engineers as part of their preparation of our reserves.

Qualifications of responsible technical persons

J. Steve Guthrie was our Senior Vice President of Business Operations and Engineering from November 2013 to January 2019. In January 2019, Mr. Guthrie announced his intent to retire from Concho at the end of 2019 and is currently serving as Special Advisor to the Company to aid in the transition of his responsibilities. Mr. Guthrie previously served as the Vice President of Texas, the Texas Asset Manager and Corporate Engineering Manager. Prior to joining the Company, Mr. Guthrie was employed by Moriah Resources as Business Development Manager, by Henry Petroleum in various engineering and operations capacities and by Exxon in several engineering and operations positions. Mr. Guthrie is a graduate of Texas Tech University with a Bachelor of Science degree in Petroleum Engineering.

Rick Morton joined the Company in 2011 as Corporate Engineering Manager. Prior to joining the Company, Mr. Morton served as Division Acquisition Coordinator for EOG Resources, Inc. Mr. Morton was also previously employed by Southwest Royalties, Inc. as Vice President and Exploitation Manager and by Merit Energy Company in various engineering positions. Mr. Morton began his career in 1983 with Arco Oil and Gas Company as an Operations/Analytical Engineer before moving to a Production Supervisor position. He is a graduate of Texas A&M University with a Bachelor of Science degree in Petroleum Engineering.

CGA. Approximately 57 percent of the proved reserves estimates shown herein at December 31, 2018 have been independently prepared by CGA, a leader of petroleum property analysis for industry and financial institutions. CGA was founded in 1960 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-693. Within CGA, the technical person primarily responsible for preparing the estimates set forth in the CGA letter dated January 23, 2019, filed as an exhibit to this Annual Report on Form 10-K, was Mr. Zane Meekins. Mr. Meekins has been a practicing consulting petroleum engineer at CGA since 1989. Mr. Meekins is a Registered Professional Engineer in the State of Texas (License No. 71055) and has over 31 years of practical experience in petroleum engineering, with over 29 years of experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1987 with a Bachelor of Science degree in Petroleum Engineering. Mr. Meekins meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserve definitions and guidelines.

NSAI. Approximately 43 percent of the proved reserve estimates shown herein at December 31, 2018 have been independently prepared by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical person primarily responsible for preparing the estimates set forth in the NSAI letter dated January 21, 2019, filed as an exhibit to this Annual Report on Form 10-K, was Mr. Craig H. Adams. Mr. Adams, a Licensed Professional Engineer in the State of Texas (License No. 68137), has been practicing consulting petroleum engineering at NSAI since 1997 and has over 11 years of prior industry experience. He graduated from Texas Tech University in 1985 with a Bachelor of Science Degree in Petroleum Engineering. Mr. Adams meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserve definitions and guidelines.

Our oil and natural gas reserves. The following table sets forth our estimated proved oil and natural gas reserves at December 31, 2018. Our reserve estimates and our calculation of future net cash flows are based on SEC pricing of (i) $62.04 per Bbl WTI posted oil price and $3.10 per MMBtu Henry Hub spot natural gas price, adjusted for location and quality differentials by property.

	Oil (MMBbl)	**Natural Gas (Bcf)**	**Total (MMBoe)**
Operating Areas:			
Delaware Basin	410	1,586	674
Midland Basin	340	1,036	513
Other	-	2	-
Total	750	2,624	1,187

The following table sets forth our estimated proved reserves by category at December 31, 2018:

	Oil (MMBbl)	**Natural Gas (Bcf)**	**Total (MMBoe)**	**Percent of Total**
Proved developed producing	485	1,882	799	67%
Proved developed non-producing	15	59	25	2%
Proved undeveloped	250	683	363	31%
Total proved	750	2,624	1,187	100%
Total proved developed	500	1,941	824	69%

Changes to proved reserves. The following table sets forth the changes in our proved reserve volumes by area during the year ended December 31, 2018 (in MMBoe):

	Production	**Extensions and Discoveries**	**Purchases of Minerals-in-Place**	**Sales of Minerals-in-Place**	**Revisions of Previous Estimates**
Operating Areas:					
Delaware Basin	(66)	134	102	(8)	(61)
Midland Basin	(30)	92	206	(9)	(13)
Total	(96)	226	308	(17)	(74)

Extensions and discoveries. Extensions and discoveries of approximately 226 MMBoe are primarily the result of our continued success from our horizontal drilling programs in our operating areas. Proved developed reserves increased approximately 87 MMBoe due to our drilling activity in 2018, and based upon this activity, we added approximately 139 MMBoe of new proved undeveloped reserves.

Purchases and sales of minerals-in-place. Our purchases of minerals-in-place were primarily the result of the RSP Acquisition in July 2018 which added approximately 275 MMBoe. The remainder of the purchases of minerals-in-place was primarily the result of certain acquisitions and nonmonetary transactions during 2018, which added approximately 25 MMBoe in the Midland Basin and 8 MMBoe in the Delaware Basin. Our sales of minerals-in-place were primarily the result of various divestitures and nonmonetary transactions during 2018.

Revisions of previous estimates. Revisions of previous estimates are primarily composed of (i) 77 MMBoe of negative revisions due to proved undeveloped reserves reclassified to unproved, (ii) 15 MMBoe of net negative performance and other revisions and (iii) 18 MMBoe of positive price revisions. Our proved reserves at December 31, 2018 were determined using the SEC prices of $62.04 per Bbl of oil for WTI and $3.10 per MMBtu of natural gas for Henry Hub spot, as compared to corresponding prices of $47.79 per Bbl of oil and $2.98 per MMBtu of natural gas at December 31, 2017. As we continue to transition our development program to large-scale projects and evaluate and analyze our producing oil and natural gas properties and drilling prospects, certain properties were no longer expected to be developed within five years of the date of their initial recognition and were removed from our current drilling plans. This includes certain properties with a lower liquids content and certain non-operated properties that we reclassified due to the uncertainty regarding the timing of development.

Net negative performance and revisions primarily related to 27 MMBoe of downward revisions to certain proved developed producing properties in our Yeso field, partially offset by other positive performance revisions.

Proved undeveloped reserves. At December 31, 2018, we had approximately 363 MMBoe of proved undeveloped reserves as compared to 252 MMBoe at December 31, 2017.

The following table summarizes the changes in our proved undeveloped reserves during 2018 (in MMBoe):

At December 31, 2017	252
Extensions and discoveries	139
Purchases of minerals-in-place	113
Sales of minerals-in-place	(2)
Revisions of previous estimates	(69)
Conversion to proved developed reserves	(70)
At December 31, 2018	363

Extensions and discoveries. Extensions and discoveries of approximately 139 MMBoe are primarily the result of new proved undeveloped locations that were added as a result of our exploration program during 2018.

Purchases and sales of minerals-in-place. Our purchases of minerals-in-place were primarily the result of the RSP Acquisition in July 2018 which added approximately 103 MMBoe. The remainder of the purchases of minerals-in-place was primarily the result of certain acquisitions and nonmonetary transactions during 2018 which added approximately 7 MMBoe in the Midland Basin and 3 MMBoe in the Delaware Basin. Our sales of minerals-in-place were primarily the result of certain divestitures and nonmonetary transactions in the Midland Basin during 2018.

Revisions of previous estimates. Net negative revisions of previous estimates of approximately 69 MMBoe are primarily attributable to 77 MMBoe of negative revisions primarily due to proved undeveloped reserves reclassified to unproved, partially offset by approximately 8 MMBoe of net positive revisions. As we continue to transition our development program to large-scale projects and evaluate and analyze our producing oil and natural gas properties and drilling prospects, certain properties were no longer expected to be developed within five years of the date of their initial recognition and were removed from our current drilling plans. This includes certain properties with a lower liquids content and certain non-operated properties that we reclassified due to the uncertainty regarding the timing of development.

Conversion to proved developed reserves. The following table sets forth proved undeveloped reserves converted to proved developed reserves and the associated investment required to convert proved undeveloped reserves to proved developed reserves during the year ended December 31, 2018:

Proved Undeveloped Reserves Converted to Proved Developed Reserves			**Investment in Conversion of Proved Undeveloped Reserves to Proved Developed Reserves**	
Oil (MMBbl)	**Natural Gas (Bcf)**	**Total (MMBoe)**	**(in millions)**	
45	151	70(a)	$	695(a)

(a) Of this amount, approximately $115 million was spent in 2018 on proved undeveloped reserves that were not converted to proved developed reserves by December 31, 2018. In addition, this amount does not include 10 MMBoe and $88 million of costs incurred to convert proved undeveloped reserves to proved developed reserves acquired in the RSP Acquisition.

Historically, our drilling programs were substantially funded from our cash flows from operations and borrowings from our Credit Facility. Based on our current expectations over the next five years of our cash flows and drilling programs, which includes drilling of proved undeveloped and unproved locations, we believe that we can continue to substantially fund our drilling activities from our cash flow and with borrowings from our Credit Facility, if needed. Based on SEC pricing as of December 31, 2018, estimated future development costs required for the development of proved undeveloped reserves are projected to be approximately $3.3 billion over the next five years.

Developed and Undeveloped Acreage

The following table presents our total gross and net developed and undeveloped acreage by area at December 31, 2018:

(in thousands)	Developed Acres (a) Gross	Net	Undeveloped Acres (b) Gross	Net	Total Acres Gross	Net
Operating Areas:						
Delaware Basin	371	262	273	172	644	434
Midland Basin	253	160	62	46	315	206
Total	624	422	335	218	959	640

(a) Developed acres are acres attributable or assigned to wells producing economic quantities of oil or natural gas and do not include undrilled acreage held by production.

(b) Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or natural gas regardless of whether such acreage contains proved reserves.

The following table sets forth the future expiration amounts of our gross and net undeveloped acreage at December 31, 2018 by operating area:

(in thousands)	2019 Gross	Net	2020 Gross	Net	2021 Gross	Net	Thereafter Gross	Net
Operating Areas:								
Delaware Basin	13	11	30	5	13	3	8	8
Midland Basin (a)	-	1	1	-	-	-	-	-
Total	13	12	31	5	13	3	8	8

(a) Expiring net acres are greater than gross acres in our Midland Basin operating area in 2019 as certain leases contain undivided interests and have multiple net acreage expiration dates within the same tract of land. Expirations of net acres are shown in the year they occur, while the expirations of gross acres are shown in the final year of net acre expiration.

At December 31, 2018, we had approximately 95,000 gross and 81,000 net acres subject to a continuous development clause or similar drilling commitments. Historically, we have not experienced material expiration of acres due to non-compliance and we do not anticipate any material expirations during 2019 or any future periods.

38

Drilling Activities

For summary tables that set forth information with respect to wells drilled and completed for the years ended December 31, 2018, 2017 and 2016, see “Item 1. Business—Drilling Activities.”

Our Production, Prices and Expenses

For a summary table that sets forth information concerning our production and operating data from operations for the years ended December 31, 2018, 2017 and 2016, see “Item 1. Business—Our Production, Prices and Expenses.”

Productive Wells

For a summary table that sets forth the number of productive oil and natural gas wells on our properties at December 31, 2018, 2017 and 2016, see “Item 1. Business—Productive Wells.”

Title to Our Properties

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a more thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect defects affecting those properties, we are typically responsible for curing any such defects at our expense. We generally will not commence drilling operations on a property until we have cured known material title defects on such property. We have reviewed the title to substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry. Prior to completing an acquisition of producing oil and natural gas properties, we perform title reviews on the most significant properties, and depending on the materiality of properties, we may obtain a title opinion or review or update previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens for current taxes and other burdens that we believe do not materially interfere with the use or affect our carrying value of the properties.

Item 3. 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 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market Information

Our common stock trades on the NYSE under the symbol "CXO." As of February 15, 2019, there were 1,461 holders of record of our common stock.

Dividend Policy

On February 19, 2019, the Company's board of directors approved a cash dividend of $0.125 per share for the first quarter of 2019. The total cash dividend, including the cash dividend on unvested restricted stock awards, of $25 million is expected to be paid on March 29, 2019. The Company intends to continue to pay a quarterly dividend of $0.125 in the near future; however, any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant. Covenants contained in our Credit Facility and the indentures governing our senior notes could limit the payment of dividends. See Note 10 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Repurchases of Equity Securities

The following table sets forth our share repurchase activity for each period presented:

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
October 1, 2018 - October 31, 2018	366	$ 148.70	-	
November 1, 2018 - November 30, 2018	104	$ 135.76	-	
December 1, 2018 - December 31, 2018	3,047	$ 104.01	-	

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

Item 6. Selected Financial Data

This section presents our selected historical consolidated financial data. The selected historical consolidated financial data presented below is not intended to replace our historical consolidated financial statements. You should read the following data along with “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and the consolidated financial statements and related notes, each of which is included in this report.

Selected Historical Financial Information

Our results of operations for the periods presented below may not be comparable either from period to period or going forward. We have completed numerous acquisitions, dispositions and nonmonetary transactions that impact the comparability of the selected financial data between periods. In addition, and due in part to the aforementioned factors, the selected financial data between periods was impacted by significant changes in our capital structure, including various debt and equity financing transactions.

Our financial data below is derived from (i) our audited consolidated financial statements included in this report and (ii) other audited consolidated financial statements of ours not included in this report.

	Years Ended December 31,				
(in millions, except per share amounts)	**2018 (a)**	**2017 (a)**	**2016 (a) (b)**	**2015**	**2014**
Statement of operations data:					
Total operating revenues	$ 4,151	$ 2,586	$ 1,635	$ 1,804	$ 2,660
Total operating costs and expenses	(1,221)	(1,515)	(3,709)	(1,479)	(1,581)
Income (loss) from operations	$ 2,930	$ 1,071	$ (2,074)	$ 325	$ 1,079
Net income (loss)	$ 2,286	$ 956	$ (1,462)	$ 66	$ 538
Earnings per share:					
Basic net income (loss)	$ 13.28	$ 6.44	$ (10.85)	$ 0.54	$ 4.89
Diluted net income (loss)	$ 13.25	$ 6.41	$ (10.85)	$ 0.54	$ 4.88
Other financial data:					
Net cash provided by operations	$ 2,558	$ 1,695	$ 1,384	$ 1,530	$ 1,746
Net cash used in investing activities	$ (2,216)	$ (1,719)	$ (2,225)	$ (2,602)	$ (2,618)
Net cash provided by (used in) financing activities	$ (342)	$ (29)	$ 665	$ 1,301	$ 872
Adjusted EBITDAX (non-GAAP) (d)	$ 2,752	$ 1,893	$ 1,633	$ 1,713	$ 2,033

			December 31,		
(in millions)	**2018 (a)**	**2017 (a)**	**2016 (a) (c)**	**2015 (c)**	**2014**
Balance sheet data:					

Cash and cash equivalents	$ -	$ -	$ 53	$ 229	$ -
Property and equipment, net	22,313	13,041	11,302	10,976	10,206
Total assets	26,294	13,732	12,119	12,642	11,752
Long-term debt	4,194	2,691	2,741	3,332	3,469
Stockholders' equity	18,768	8,915	7,623	6,943	5,281

(a) See Notes 4 and 5 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a summary of acquisitions, divestitures and nonmonetary transactions included in our financial data for the selected years. In addition, see Note 10 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a description of associated debt financing transactions.

(b) A non-cash impairment charge of approximately $1.5 billion is included in income (loss) from operations for the year ended December 31, 2016.

(c) During 2016 and 2015, we issued approximately 10.4 million and 15.8 million shares of our common stock, respectively, in public offerings and received net proceeds of approximately $1.3 billion and $1.5 billion, respectively.

(d) Adjusted EBITDAX is defined as net income (loss), plus (1) exploration and abandonments, (2) depreciation, depletion and amortization, (3) accretion of discount on asset retirement obligations, (4) impairments of long-lived assets, (5) non-cash stock-based compensation, (6) (gain) loss on derivatives, (7) net cash receipts from (payments on) derivatives, (8) (gain) loss on disposition of assets, net, (9) interest expense, (10) loss on extinguishment of debt, (11) gain on equity method investment distribution, (12) RSP transaction costs and (13) federal and state income tax expense (benefit). See "Item 1. Business —Non-GAAP Financial Measures and Reconciliations."

Item 7. 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, as well as the selected historical consolidated financial data included elsewhere in this report.

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" and "Item 1A. Risk Factors" for further details about these 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. We are one of the largest operators 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, and we are actively developing our resource base utilizing large-scale development projects, which include long-lateral wells and multi-well pad locations, throughout our operating areas. Oil comprised 63 percent of our 1,187 MMBoe of estimated proved reserves at December 31, 2018 and 64 percent of our 96 MMBoe of production for 2018. 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 77 percent of our 9,277 gross wells at December 31, 2018. 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

On July 19, 2018, we completed the RSP Acquisition, which, among other things, impacted the comparability of our results of operations. Our financial and operating performance for 2018 included the following highlights:

• Net income was $2,286 million ($13.25 per diluted share) as compared to net income of $956 million ($6.41 per diluted share) in 2017. The increase was primarily due to:

• $1,565 million increase in oil and natural gas revenues as a result of a 36 percent increase in production and a 18 percent increase in commodity price realizations per Boe (excluding the effects of derivative activities);

• $958 million change in (gain) loss on derivatives due to a $832 million gain on derivatives during 2018, as compared to a $126 million loss during 2017;

• $122 million net increase in gain on disposition of assets due to a gain of approximately $800 million during 2018 primarily attributable to the February 2018 acquisition and divestiture primarily in the Midland Basin, the January 2018 divestiture in the Delaware Basin and the contribution of certain infrastructure assets to WaterBridge Operating LLC (“WaterBridge”) in December 2018, as compared to a net gain of approximately $678 million during 2017 primarily attributable to our disposition of ACC; and

• $86 million increase in other income, primarily due to a gain of approximately $103 million on the equity method investment distribution received from Oryx;

partially offset by:

• $678 million increase in our income tax provision primarily due to the income tax benefit recorded in 2017 as a result of the Tax Cuts and Jobs Act (the “TCJA”);

• $332 million increase in depreciation, depletion and amortization expense, primarily due to an increase in production, partially offset by a lower depletion rate per Boe;

• $182 million increase in production expense, primarily due to (i) increased production associated with our wells successfully drilled and completed in 2017 and 2018, (ii) our acquisitions and nonmonetary transactions during the fourth quarter of 2017 and during 2018, (iii) increased cost of services and (iv) increased workover costs;

• $106 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; and

• $36 million increase in transaction costs, primarily due to consulting, investment banking, advisory, legal and other fees related to the RSP Acquisition.

• Average daily sales volumes increased by 36 percent from 192,658 Boe per day during 2017 to 262,937 Boe per day during 2018.

• Net cash provided by operating activities increased by approximately $863 million to $2,558 million for 2018, as compared to $1,695 million in 2017, primarily due to increased oil and natural gas revenues, partially offset by (i) changes related to cash settlements on derivatives, (ii) increased production expense and (iii) increased production tax expense.

Commodity Prices

Our results of operations are heavily influenced by commodity prices. See “Item 1A. Risk Factors” for a description of the factors that may impact future commodity prices, including the price of oil, natural gas and natural gas liquids.

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 hedge a portion of our commodity price risk to mitigate the impact of price volatility on our business. See Notes 9 and 18 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding our commodity derivative positions at December 31, 2018 and additional derivative contracts entered into subsequent to December 31, 2018, respectively.

The following table sets forth the average NYMEX oil and natural gas prices for the years ended December 31, 2018, 2017 and 2016, as well as the high and low NYMEX prices for the same periods:

	Years Ended December 31,		
	2018	**2017**	**2016**
Average NYMEX prices:			
Oil (Bbl)	$ 64.81	$ 50.97	$ 43.42
Natural gas (MMBtu)	$ 3.07	$ 3.02	$ 2.56
High and Low NYMEX prices:			
Oil (Bbl):			
High	$ 76.41	$ 60.42	$ 54.06
Low	$ 42.53	$ 42.53	$ 26.21
Natural gas (MMBtu):			
High	$ 4.84	$ 3.72	$ 3.93
Low	$ 2.55	$ 2.56	$ 1.64

Further, the NYMEX oil price and NYMEX natural gas price reached highs and lows of $55.59 and $45.41 per Bbl and $3.59 and $2.55 per MMBtu, respectively, during the period from January 1, 2019 to February 15, 2019. At February 15, 2019, the NYMEX oil price and NYMEX natural gas price were $55.59 per Bbl and $2.63 per MMBtu, respectively.

Historically, and during the year ended December 31, 2018, 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. Because of our liquids-rich natural gas stream, and the related value of the natural gas liquids being included in our natural gas revenues, our realized natural gas price (excluding the effects of derivatives) reflected a price greater than the related NYMEX natural gas price for the year ended December 31, 2018. The average Mont Belvieu price for a blended barrel of natural gas liquids was $29.94 per Bbl, $25.06 per Bbl and $18.08 per Bbl during the years ended December 31, 2018, 2017 and 2016, respectively.

Potential cost inflation. Oilfield service and supply costs are also subject to supply and demand dynamics. As companies expand their drilling and development activities, the demand for third-party oilfield services and suppliers may also increase. As such, when commodity prices begin to trend upward, we expect demand for oilfield services and supplies to grow, and the costs of drilling, equipping and operating our wells and infrastructure could begin to rise. Our lease operating expenses per Boe increased during 2018 as compared to 2017, partially due to cost inflation resulting from these factors.

Recent Events

2019 capital budget. In October 2018, our board of directors approved our 2019 capital budget of up to $3.8 billion. With current commodity prices, we expect to spend between $2.8 billion and $3.0 billion on drilling and completion activity.

2019 dividends. On February 19, 2019, our board of directors declared a cash dividend of $0.125 per share for the first quarter of 2019. The total cash dividend, including cash dividend on unvested restricted stock awards, of $25 million is expected to be paid on March 29, 2019 to stockholders of record as of March 1, 2019.

Marketing contract. Consistent with our strategy of diversifying our oil pricing, in January 2019, we entered into a firm sales agreement with a third-party purchaser. The purchaser provides an integrated transportation and marketing strategy, including ample dock capacity. The agreement has a term that ends five years after the startup of Cactus II Pipeline system and requires that we deliver 50,000 barrels of oil per day that will receive waterborne market pricing.

RSP Acquisition. On July 19, 2018, we completed the RSP Acquisition. Under the terms of the Agreement and Plan of Merger (the “Acquisition Agreement”), each share of RSP common stock was converted into 0.320 of a share of our common stock. We issued approximately 51 million shares of common stock at a price of $148.27 per share, resulting in total consideration paid to the former RSP shareholders of approximately $7.5 billion. Refer to Note 4 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding the RSP Acquisition.

Long-term debt. On July 2, 2018, we issued $1,600 million in aggregate principal amount of unsecured senior notes, consisting of $1,000 million in aggregate principal amount of 4.3% unsecured senior notes due 2028 (the “4.3% Notes”) and $600 million in aggregate principal amount of 4.85% unsecured senior notes due 2048 (the “4.85% Notes” and, together with the 4.3% Notes, the “Notes”). The net proceeds of approximately $1,579 million were used to redeem and cancel all of RSP’s outstanding $700 million aggregate principal amount of 6.625% unsecured senior notes due 2022 (the “RSP 2022 Notes”) and $450 million aggregate principal amount of 5.25% unsecured senior notes due 2025 (the “RSP 2025 Notes” and, together with the RSP 2022 Notes, the “RSP Notes”) and to repay a portion of the outstanding indebtedness under RSP’s existing credit facility. We repaid the remaining balance under RSP’s credit facility with borrowings under our Credit Facility, resulting in a total payoff of $1,773 million, which included the accrued interest and premiums on the RSP notes and other fees and expenses related to RSP’s credit facility.

Derivative Financial Instruments

Derivative financial instrument exposure. At December 31, 2018, the fair value of our financial derivatives was a net asset of $695 million. Under the terms of our financial derivative instruments, we do not have exposure to potential "margin calls" on our financial derivative instruments. 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.

New commodity derivative contracts. After December 31, 2018, we entered into derivative contracts to hedge additional amounts of estimated future production. Refer to Note 18 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding these commodity derivative contracts.

Results of Operations

The following table sets forth summary production and operating data for the years ended December 31, 2018, 2017 and 2016. The actual historical data in this table excludes results from the RSP Acquisition for periods prior to July 19, 2018 and 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 acquisitions and divestitures, the historical information presented below should not be interpreted as being indicative of future results.

	Years Ended December 31,					
		2018		**2017**		**2016**
Production and operating data:						
Net production volumes:						
Oil (MBbl)		61,251		43,472		33,840
Natural gas (MMcf)		208,326		161,089		127,481
Total (MBoe)		95,972		70,320		55,087
Average daily production volumes:						
Oil (Bbl)		167,811		119,101		92,459
Natural gas (Mcf)		570,756		441,340		348,309
Total (Boe)		262,937		192,658		150,511
Average prices per unit:						
Oil, without derivatives (Bbl)	$	56.22	$	48.13	$	39.90
Oil, with derivatives (Bbl) (a)	$	52.73	$	49.93	$	57.90
Natural gas, without derivatives (Mcf)	$	3.40	$	3.07	$	2.23
Natural gas, with derivatives (Mcf) (a)	$	3.37	$	3.06	$	2.36
Total, without derivatives (Boe)	$	43.25	$	36.78	$	29.68
Total, with derivatives (Boe) (a)	$	40.98	$	37.88	$	41.03
Operating costs and expenses per Boe: (b)						
Oil and natural gas production	$	6.14	$	5.80	$	5.81
Production and ad valorem taxes	$	3.19	$	2.82	$	2.38
Gathering, processing and transportation	$	0.58	$	-	$	-
Depreciation, depletion and amortization	$	15.41	$	16.29	$	21.19
General and administrative	$	3.25	$	3.46	$	4.09

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

(in millions)	Years Ended December 31, 2018	2017	2016
Net cash receipts from (payments on) derivatives:			
Oil derivatives	$ (213)	$ 79	$ 609
Natural gas derivatives	(5)	-	16
Total	$ (218)	$ 79	$ 625

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.

(b) Per Boe amounts calculated using dollars and volumes rounded to thousands.

The following table presents selected production data for the fields that represent greater than 15 percent of our total proved reserves at December 31, 2018, 2017 and 2016:

	Year Ended December 31,		
	2018	**2017**	**2016**
Production:			
Delaware Basin:			
Oil (MMBbl)	34	25	21
Natural gas (Bcf)	130	103	80
Total (MMBoe)	56	42	34
Midland Basin:			
Oil (MMBbl)	21	11	6
Natural gas (Bcf)	52	30	20
Total (MMBoe)	30	16	9
Yeso:			
Oil (MMBbl)	(a)	7	7
Natural gas (Bcf)	(a)	28	27
Total (MMBoe)	(a)	12	12

(a) Represents less than 15% of our total proved reserves for the year indicated. The Yeso field is part of our Delaware Basin operating area.

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017

Oil and natural gas revenues. Oil and natural gas operating revenues were $4,151 million for the year ended December 31, 2018, an increase of $1,565 million (61 percent) from $2,586 million for 2017. This increase was primarily due to the increase in oil and natural gas production, partially due to the RSP Acquisition, as well as the increase in realized oil and natural gas prices (excluding the effects of derivative activities). Additionally, on January 1, 2018, we adopted ASC 606, which requires certain costs related to gathering, processing and transportation to be separately presented on the consolidated statements of operations. Prior to the adoption of ASC 606, these costs were generally accounted for as a deduction to revenue and included within total operating revenues on the consolidated statements of operations. We elected to use the modified retrospective approach for adopting ASC 606, and as such, prior period amounts have not been restated. See Note 2 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for more information regarding the adoption of ASC 606. Specific factors affecting oil and natural gas revenues include the following:

- total oil production was 61,251 MBbl for the year ended December 31, 2018, an increase of 17,779 MBbl (41 percent) from 43,472 MBbl for 2017;

- average realized oil price (excluding the effects of derivative activities) was $56.22 per Bbl during the year ended December 31, 2018, an increase of 17 percent from $48.13 per Bbl during 2017. For the year ended December 31, 2018, our crude oil price differential relative to NYMEX was $(8.59) per Bbl, or a realization of approximately 87 percent, as compared to a crude oil price differential relative to NYMEX of $(2.84) per Bbl, or a realization of approximately 94 percent, for 2017. The basis differential (referred to as the “Mid-Cush differential”) between the location of Midland, Texas and Cushing, Oklahoma (NYMEX pricing location) for our oil directly impacts our realized oil price. For the years ended December 31, 2018 and 2017, the average market Mid-Cush differential was a price reduction of $6.51 per Bbl and $0.30 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. Our crude oil price differential relative to NYMEX excluding the Mid-Cush differential was $2.08 per Bbl for the year ended December 31, 2018, as compared to $2.54 per Bbl for the year ended December 31, 2017;

- total natural gas production was 208,326 MMcf for the year ended December 31, 2018, an increase of 47,237 MMcf (29 percent) from 161,089 MMcf for 2017; and

- average realized natural gas price (excluding the effects of derivative activities) was $3.40 per Mcf during the year ended December 31, 2018, an increase of 11 percent from $3.07 per Mcf during 2017. For the years ended December 31, 2018 and 2017, we realized approximately 111 percent and 102 percent, respectively, of the average NYMEX natural gas prices for the respective periods. Historically, and during the year ended December 31, 2018, 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. Because of our liquids-rich natural gas stream and the related value of the natural gas liquids being included in our natural gas revenues, our realized natural gas price (excluding the effects of derivatives) reflected a price greater than the related NYMEX natural gas price for the year ended December 31, 2018. The increase in our realized natural gas price (excluding the effects of derivatives) as a percentage of NYMEX during the year ended December 31, 2018 as compared to 2017 was primarily due to an increase in the average Mont Belvieu price for a blended barrel of natural gas liquids. The average Mont Belvieu price for a blended barrel of natural gas liquids was $29.94 per Bbl and $25.06 per Bbl during the years ended December 31, 2018 and 2017, respectively. The increase in our realized natural gas price was also due to the adoption of ASC 606, as our natural gas realized price was $0.16 per Mcf higher than what it would have been under the previous revenue standard. However, the increase was partially offset by lower regional market prices for natural gas, in part due to the widening of the regional differentials. During the latter part of 2018, amid concerns of rising natural gas production relative to natural gas takeaway in the Permian Basin, the natural gas price differential increased significantly. For example, during the fourth quarter of 2018, we realized approximately 76 percent of the average NYMEX natural gas prices.

Oil and natural gas production expenses. The following table provides the components of our oil and natural gas production expenses for the years ended December 31, 2018 and 2017:

	Years Ended December 31,			
	2018		2017	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Lease operating expenses	$ 553	$ 5.76	$ 387	$ 5.50
Workover costs	37	0.38	21	0.30
Total oil and natural gas production expenses	$ 590	$ 6.14	$ 408	$ 5.80

Lease operating expenses were $553 million ($5.76 per Boe) for the year ended December 31, 2018, which was an increase of $166 million (43 percent) from $387 million ($5.50 per Boe) for the year ended December 31, 2017. The increase in lease operating expenses was primarily the result of increased production activities due to (i) additional wells successfully drilled and completed (ii) additional wells added from acquisitions, primarily the RSP Acquisition and (iii) overall increased cost of services. The increase in lease operating expenses per Boe was primarily due to the increase in lease operating expenses noted above, partially offset by an increase in production.

Workover costs were $37 million ($0.38 per Boe) for the year ended December 31, 2018, which was an increase of $16 million from $21 million ($0.30 per Boe) during 2017. The increase in workover costs during the year ended December 31, 2018 as compared to 2017 was primarily due to increased workover activity and higher cost of services. The increase in workover costs per Boe was primarily due to the increase in workover costs noted above, partially offset by an increase in production.

Production and ad valorem taxes. The following table provides the components of our production and ad valorem tax expenses for the years ended December 31, 2018 and 2017:

	Years Ended December 31,			
	2018		2017	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**

Production taxes	$	272	$	2.84	$	181	$	2.58
Ad valorem taxes		33		0.35		18		0.24
Total production and ad valorem taxes	$	305	$	3.19	$	199	$	2.82

Production taxes per unit of production were $2.84 per Boe during the year ended December 31, 2018, an increase of 10 percent from $2.58 per Boe during 2017. Over the same period, our revenue per Boe (excluding the effects of derivatives) increased 18 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. Ad valorem taxes increased by $15 million primarily due to additional wells drilled and completed, new wells acquired in the RSP Acquisition and an increase in property values. The increase in ad valorem taxes per Boe was primarily due to an increase in property values.

Gathering, processing and transportation costs. The following table shows the gathering, processing and transportation costs for the year ended December 31, 2018:

	Year Ended December 31, 2018	
(in millions, except per unit amounts)	**Amount**	**Per Boe**
Gathering, processing and transportation costs	$ 55	$ 0.58

Gathering, processing and transportation costs were $55 million ($0.58 per Boe) for the year ended December 31, 2018. On January 1, 2018, we adopted ASC 606, which requires certain amounts related to gathering, processing and transportation costs to be separately presented on the consolidated statements of operations. Prior to the adoption of ASC 606, the majority of these costs were accounted for as a deduction to revenue and included within total operating revenues on the consolidated statements of operations. We have elected to use the modified retrospective approach for adopting ASC 606, and as such, prior period amounts have not been restated. In addition, our gathering, processing and transportation costs are impacted by production volumes and fixed costs associated with certain contracts.

Exploration and abandonments expense. The following table provides the components of our exploration and abandonments expense for the years ended December 31, 2018 and 2017:

	Years Ended December 31,	
(in millions)	**2018**	**2017**
Geological and geophysical	$ 12	$ 13
Leasehold abandonments	35	27
Other	18	19
Total exploration and abandonments	$ 65	$ 59

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 years ended December 31, 2018 and 2017, we recorded approximately $35 million and $27 million, respectively, of leasehold abandonments. Our leasehold abandonments for the year ended December 31, 2018 and 2017 were primarily related to certain expiring acreage and acreage where we had no future plans to drill.

Our other expense for the periods presented above primarily consists of surface and title costs on locations we no longer intend to drill, certain plugging costs and delay rentals.

Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the years ended December 31, 2018 and 2017:

	Years Ended December 31,			
	2018		2017	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Depletion of proved oil and natural gas properties	$ 1,453	$ 15.14	$ 1,122	$ 15.95
Depreciation of other property and equipment	22	0.23	21	0.29
Amortization of intangible assets	3	0.04	3	0.05
Total depletion, depreciation and amortization	$ 1,478	$ 15.41	$ 1,146	$ 16.29
Oil price used to estimate proved oil reserves at period end	$ 62.04		$ 47.79	
Natural gas price used to estimate proved natural gas reserves at period end	$ 3.10		$ 2.98	

Depletion of proved oil and natural gas properties was $1,453 million ($15.14 per Boe) for the year ended December 31, 2018, an increase of $331 million (30 percent) from $1,122 million ($15.95 per Boe) for 2017. The increase in depletion expense was primarily due to an increase in production, partially offset by a lower depletion rate per Boe. The decrease in depletion expense per Boe was primarily due to the increase in proved reserves due to our successful exploratory drilling program, cost reductions and higher oil prices, partially offset by the RSP Acquisition.

General and administrative expenses. The following table provides components of our general and administrative expenses for the years ended December 31, 2018 and 2017:

	Years Ended December 31,			
	2018		2017	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
General and administrative expenses	$ 248	$ 2.58	$ 200	$ 2.85
Less: Operating fee reimbursements	(19)	(0.19)	(16)	(0.24)
Non-cash stock-based compensation	82	0.86	60	0.85
Total general and administrative expenses	$ 311	$ 3.25	$ 244	$ 3.46

General and administrative expenses were approximately $311 million ($3.25 per Boe) for the year ended December 31, 2018, an increase of $67 million (27 percent) from $244 million ($3.46 per Boe) for 2017. The increase in cash general and administrative and non-cash stock-based compensation expenses was primarily driven by the increase in employee headcount. The decrease in total general and administrative expenses per Boe was primarily the result of increased production, partially offset by the increase in total general and administrative expenses 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 $19 million and $16 million during the years ended December 31, 2018 and 2017, respectively.

Gain (loss) on derivatives. The following table sets forth the gain (loss) on derivatives for the years ended December 31, 2018 and 2017:

	Years Ended December 31,			
(in millions)	**2018**		**2017**	
Gain (loss) on derivatives:				
Oil derivatives	$	848	$	(172)
Natural gas derivatives		(16)		46
Total	$	832	$	(126)

The following table represents our net cash receipts from (payments on) derivatives for the years ended December 31, 2018 and 2017:

	Years Ended December 31,			
(in millions)	**2018**		**2017**	
Net cash receipts from (payments on) derivatives:				
Oil derivatives	$	(213)	$	79
Natural gas derivatives		(5)		-
Total	$	(218)	$	79

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 future commodity price outlook increases between measurement periods, we will have mark-to-market losses. See Note 8 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding significant judgments made in classifying financial instruments in the fair value hierarchy.

Gain on disposition of assets, net. During the years ended December 31, 2018 and 2017, we recognized a non-cash net gain on disposition of assets of approximately $800 million and $678 million respectively.

The net gain during 2018 was primarily due to (i) a gain of approximately $575 million related to our February 2018 acquisition and divestiture primarily in the Midland Basin, (ii) a gain of approximately $134 million related to our Delaware Basin divestiture in January 2018 and (iii) a gain of approximately $79 million related to the contribution of certain infrastructure assets in the southern portion of our Delaware Basin to WaterBridge in December 2018. See Note 2 of the Notes to Consolidated Financial Statements included in “Item 8. Financials Statements and Supplementary Data” for additional information regarding our transaction with WaterBridge. In addition, during 2018, we completed multiple nonmonetary transactions that included the exchange of both proved and unproved oil and natural gas properties. Certain of these transactions were accounted for at fair value, and as a result, we recorded pre-tax gains of approximately $15 million.

In February 2017, we closed on the 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.

See Note 5 of the Notes to Consolidated Financial Statements included in “Item 8. Financials Statements and Supplementary Data” for additional information regarding our significant divestitures and nonmonetary transactions.

Interest expense. The following table sets forth interest expense, weighted average interest rates and weighted average debt balances for the years ended December 31, 2018 and 2017:

	Years Ended December 31,			
(in millions)		**2018**		**2017**
Interest expense, as reported	$	149	$	146
Capitalized interest		8		3
Interest expense, excluding impact of capitalized interest	$	157	$	149
Weighted average interest rate – Credit Facility		4.5%		3.5%
Weighted average interest rate – senior notes		4.3%		5.0%
Total weighted average interest rate		4.3%		5.0%
Weighted average Credit Facility balance	$	172	$	100
Weighted average senior notes balance		3,195		2,658
Total weighted average debt balance	$	3,367	$	2,758

The increase in interest expense was due to the increase in the weighted average debt balance, partially offset by the decrease in the weighted average interest rate and an increase in capitalized interest. The increase in the weighted average debt balance was due primarily to the Notes issued in connection with the RSP Acquisition.

Loss on extinguishment of debt. We recorded a loss on extinguishment of debt of $66 million for the year ended December 31, 2017. This amount includes: (i) approximately $36 million associated with the premium paid for the cash tender offer ("Tender Offer") and redemption of the 5.5% unsecured senior notes due 2022 (the "5.5% Notes"), 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 our Credit Facility syndicate as a result of the April 2017 amendment to our Credit Facility.

Other income, net. During the year ended December 31, 2018, we recorded other income of approximately $108 million primarily related to a cash distribution received from Oryx. See Note 2 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding this distribution.

Income tax provisions. For the year ended December 31, 2018, we recorded income tax expense of approximately $603 million. For the year ended December 31, 2017, we recorded an income tax benefit of approximately $75 million, which includes the $398 million provisional income tax benefit that was recognized as a result of the favorable income tax rate change enacted through the TCJA in December 2017. At December 31, 2018, the Company completed its accounting for all of the enactment-date tax effects of the TCJA and recognized an adjustment to this provisional amount of approximately $7 million primarily related to the deductibility of certain performance-based compensation expenses.

The effective income tax rates for the years ended December 31, 2018 and 2017 were 21 percent and (9) percent, respectively. Our 2018 effective tax rate more closely aligns with the 21 percent federal statutory rate enacted by the TCJA while our 2017 effective tax rate reflects the $398 million income tax benefit recognized due to the decrease in the federal income tax rate from 35 percent to 21 percent enacted by the TCJA.

We evaluate changes to our industry, production, market conditions and changes in our forecasted drilling plan by tax jurisdiction. Our material state tax jurisdictions include Texas and New Mexico. In July 2018, as part of the RSP Acquisition, we acquired property primarily located in Texas. As such, we identified a slight shift in our projected future apportionment between New Mexico and Texas for the year ended December 31, 2018. As a result, we recognized a state deferred tax benefit of approximately $8 million for the year ended December 31, 2018. We did not identify a shift in our projected future apportionment for the year ended December 31, 2017.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

Oil and natural gas revenues. Oil and natural gas operating revenues were $2,586 million for the year ended December 31, 2017, an increase of $951 million (58 percent) from $1,635 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:

- total oil production was 43,472 MBbl for the year ended December 31, 2017, an increase of 9,632 MBbl (28 percent) from 33,840 MBbl for 2016;

- average realized oil price (excluding the effects of derivative activities) was $48.13 per Bbl during the year ended December 31, 2017, an increase of 21 percent from $39.90 per Bbl during 2016. For the year ended December 31, 2017, our crude oil price differential relative to NYMEX was $(2.84) per Bbl, or a realization of approximately 94 percent, as compared to a crude oil price differential relative to NYMEX of $(3.52) 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 year ended December 31, 2017 and 2016, the average market basis differential between WTI-Midland and WTI-Cushing was a price reduction of $0.30 per Bbl and $0.15 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 year ended December 31, 2017 as compared to 2016 primarily due to more production transported through pipelines and successful renegotiation of fixed deductions for trucked volumes;

- total natural gas production was 161,089 MMcf for the year ended December 31, 2017, an increase of 33,608 MMcf (26 percent) from 127,481 MMcf for 2016; and

- average realized natural gas price (excluding the effects of derivative activities) was $3.07 per Mcf during the year ended December 31, 2017, an increase of 38 percent from $2.23 per Mcf during 2016. For the years ended December 31, 2017 and 2016, we realized approximately 102 percent and 87 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 year ended December 31, 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 year ended December 31, 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 $25.06 per Bbl and $18.08 per Bbl during the years ended December 31, 2017 and 2016, respectively.

54

Oil and natural gas production expenses. The following table provides the components of our oil and natural gas production expenses for the years ended December 31, 2017 and 2016:

	Years Ended December 31,			
	2017		2016	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Lease operating expenses	$ 387	$ 5.50	$ 301	$ 5.46
Workover costs	21	0.30	19	0.35
Total oil and natural gas production expenses	$ 408	$ 5.80	$ 320	$ 5.81

Lease operating expenses were $387 million ($5.50 per Boe) for the year ended December 31, 2017, which was an increase of $86 million (29 percent) from $301 million ($5.46 per Boe) for the year ended December 31, 2016. The increase in lease operating expenses 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 during 2017, particularly the Reliance Acquisition and our Midland Basin acquisition, whose associated properties incur higher lease operating expense per Boe than our legacy assets and (iii) increased cost of services.

Production and ad valorem taxes. The following table provides the components of our production and ad valorem tax expenses for the years ended December 31, 2017 and 2016:

	Years Ended December 31,			
	2017		2016	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Production taxes	$ 181	$ 2.58	$ 117	$ 2.13
Ad valorem taxes	18	0.24	14	0.25
Total production and ad valorem taxes	$ 199	$ 2.82	$ 131	$ 2.38

Production taxes per unit of production were $2.58 per Boe during the year ended December 31, 2017, an increase of 21 percent from $2.13 per Boe during 2016. Over the same period, our revenue per Boe (excluding the effects of derivatives) increased 24 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 $5 million tax credit received during 2017 related to certain wells in Texas qualifying for reduced severance tax rates, as compared to $4 million in tax credit received during 2016. 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 years ended December 31, 2017 and 2016:

	Years Ended December 31,	
(in millions)	**2017**	**2016**
Geological and geophysical	$ 13	$ 8
Exploratory dry hole costs	-	7
Leasehold abandonments	27	50
Other	19	12
Total exploration and abandonments	$ 59	$ 77

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 year ended December 31, 2016 were primarily related to an uneconomic well in the Delaware Basin that was attempting to establish commercial production through testing of multiple zones. We did not recognize any exploratory dry hole costs during the year ended December 31, 2017.

For the years ended December 31, 2017 and 2016, we recorded approximately $27 million and $50 million, respectively, of leasehold abandonments. For the year ended December 31, 2017, our abandonments were primarily in the Delaware Basin related to acreage expiring and acreage where we have no future plans to drill. For the year ended December 31, 2016, our abandonments were primarily in the Delaware Basin related to (i) drilling locations that, based on multiple factors, were no longer likely to be drilled, (ii) acreage with no future development plans and (iii) expiring acreage.

Our other expense for the periods presented above primarily consists of surface and title costs on locations we no longer intend to drill, certain plugging costs and delay rentals.

Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the years ended December 31, 2017 and 2016:

	Years Ended December 31,			
	2017		2016	
(in millions, except per unit amounts)	Amount	Per Boe	Amount	Per Boe
Depletion of proved oil and natural gas properties	$ 1,122	$ 15.95	$ 1,145	$ 20.79
Depreciation of other property and equipment	21	0.29	21	0.37
Amortization of intangible assets	3	0.05	1	0.03
Total depletion, depreciation and amortization	$ 1,146	$ 16.29	$ 1,167	$ 21.19
Oil price used to estimate proved oil reserves at period end	$ 47.79		$ 39.25	
Natural gas price used to estimate proved natural gas reserves at period end	$ 2.98		$ 2.48	

Depletion of proved oil and natural gas properties was $1,122 million ($15.95 per Boe) for the year ended December 31, 2017, a decrease of $23 million (2 percent) from $1,145 million ($20.79 per Boe) for 2016. The decrease in depletion expense was primarily due to a lower depletion rate per Boe partially offset by an increase in production. The decrease in depletion expense per Boe was primarily due to (i) lower drilling and completion costs per Boe of proved developed reserves added, (ii) an overall increase in proved reserves primarily caused by our successful exploratory drilling program, the Reliance Acquisition as well as other acquisitions, and higher commodity prices, partially offset by decreased proved reserves caused by reclassification of proved undeveloped reserves to unproved reserves because they were no longer expected to be developed within five years of the date of their initial recognition 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 did not recognize an impairment charge during the year ended December 31, 2017. During the three months ended March 31, 2016, we recognized a non-cash impairment charge of approximately $1.5 billion. The impairment during the three months ended March 31, 2016 was primarily due to a decline in NYMEX strip prices, which resulted in the carrying amount of our Yeso field in the Delaware Basin to exceed the expected undiscounted future net cash flows of the field. 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. See Note 2 and Note 8 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information on impairments of long-lived assets.

General and administrative expenses. The following table provides components of our general and administrative expenses for the years ended December 31, 2017 and 2016:

	Years Ended December 31,			
	2017		2016	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
General and administrative expenses	$ 200	$ 2.85	$ 184	$ 3.33
Less: Operating fee reimbursements	(16)	(0.24)	(17)	(0.31)
Non-cash stock-based compensation	60	0.85	59	1.07
Total general and administrative expenses	$ 244	$ 3.46	$ 226	$ 4.09

General and administrative expenses were approximately $244 million ($3.46 per Boe) for the year ended December 31, 2017, an increase of $18 million (8 percent) from $226 million ($4.09 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, partially offset by the increase in cash 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 $16 million and $17 million during the years ended December 31, 2017 and 2016, respectively.

Gain (loss) on derivatives. The following table sets forth the gain (loss) on derivatives for the years ended December 31, 2017 and 2016:

(in millions)	Years Ended December 31, 2017	2016
Gain (loss) on derivatives:		
Oil derivatives	$ (172)	$ (337)
Natural gas derivatives	46	(32)
Total	$ (126)	$ (369)

The following table represents our net cash receipts from derivatives for the years ended December 31, 2017 and 2016:

(in millions)	Years Ended December 31, 2017	2016
Net cash receipts from derivatives:		
Oil derivatives	$ 79	$ 609
Natural gas derivatives	-	16
Total	$ 79	$ 625

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 future commodity price outlook increases between measurement periods, we will have mark-to-market losses. See Note 8 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding significant judgments made in classifying financial instruments in the fair value hierarchy.

Gain on disposition of assets, net. During the years ended December 31, 2017 and 2016, we recognized a gain on disposition of assets of approximately $678 million and $118 million, respectively. In February 2017, we closed on the 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 Delaware Basin for proceeds of approximately $292 million and recognized a pre-tax gain of approximately $110 million.

Interest expense. The following table sets forth interest expense, weighted average interest rates and weighted average debt balances for the years ended December 31, 2017 and 2016:

	Years Ended December 31,			
(in millions)		**2017**		**2016**
Interest expense, as reported	$	146	$	204
Capitalized interest		3		-
Interest expense, excluding impact of capitalized interest	$	149	$	204
Weighted average interest rate – Credit Facility		3.5%		-
Weighted average interest rate – senior notes		5.0%		5.9%
Total weighted average interest rate		5.0%		5.9%
Weighted average Credit Facility balance	$	100	$	-
Weighted average senior notes balance		2,658		3,182
Total weighted average debt balance	$	2,758	$	3,182

The decrease in interest expense was due to the decrease in the weighted average debt balance and the weighted average interest rate. Our weighted average debt balance decreased for the year ended December 31, 2017 as compared to 2016 primarily due to (i) the satisfaction and discharge of the 6.5% unsecured senior notes due 2022 (the “6.5% Notes”) in December 2016, (ii) the redemption of the 7.0% unsecured senior notes due 2021 (the “7.0% Notes”) in September 2016 and (iii) the repurchases and redemption of the 5.5% Notes in September 2017, partially offset by (i) the issuance of the 4.375% unsecured senior notes due 2025 (the “4.375% Notes”) in December 2016, (ii) the issuance of the 3.75% unsecured senior notes due 2027 (the “3.75% Notes”) and the 4.875% unsecured senior notes due 2047 (the “4.875% Notes” and, together with the 3.75% Notes, the “2017 Notes”) and (iii) an increase in borrowings under our Credit Facility. The decrease in interest expense was due to the overall decrease in the weighted average debt balance and an increase in capitalized interest.

Loss on extinguishment of debt. We recorded a loss on extinguishment of debt of $66 million for the year ended December 31, 2017. This amount includes: (i) approximately $36 million associated with the premium paid for the cash 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 our Credit Facility syndicate as a result of the April 2017 amendment to our Credit Facility.

We recorded a loss on extinguishment of debt of $56 million for the year ended December 31, 2016. This amount includes: (i) approximately $20 million associated with the make-whole premium paid for the early extinguishment of the 6.5% Notes in December 2016, approximately $7 million of related unamortized deferred loan costs and approximately $1 million of additional interest on the 6.5% Notes through January 16, 2017, which was paid in December 2016; and (ii) $21 million associated with the make-whole premium paid for the early redemption of the 7.0% Notes in September 2016 and approximately $7 million of related unamortized deferred loan costs.

Income tax provisions. For the year ended December 31, 2017, we recorded an income tax benefit of $75 million, which included discrete provisional income tax benefits of approximately $398 million related to the enactment of the TCJA and $6 million related to stock-based awards recorded in the income tax provision pursuant to Accounting Standards Update No. 2016-09, “Compensation–Stock Compensation (Topic 718): Improvements to Employee Share-based Payment Accounting” adopted on January 1, 2017. For the year ended December 31, 2016, we recorded an income tax benefit of $876 million primarily due to having a loss before income taxes.

The change in our income tax provision in 2017 as compared to 2016 was primarily due to the favorable impacts of the tax law changes enacted through the TCJA in December 2017 as the income tax benefit related to the federal statutory rate change more than offset our income tax expense of $308 million on income before income taxes during 2017. The effective income tax rates for the years ended December 31, 2017 and 2016 were (9) percent and 38 percent, respectively. The 2017 rate was negative due to recognizing an overall income tax benefit while having pre-tax income.

We evaluate changes to our industry, production, market conditions and changes in our forecasted drilling plan by tax jurisdiction. Our material state tax jurisdictions include Texas and New Mexico. In February 2017, we sold our ownership interest in ACC, which consisted of property in both Texas and New Mexico, and in April 2017, we completed an acquisition of assets in the Delaware Basin. We have considered these and other factors and did not identify a shift in our projected future apportionment between New Mexico and Texas for the year ended December 31, 2017. In October 2016, we purchased

Texas-based assets in the Reliance Acquisition for approximately $1.7 billion, which caused a shift in our projected future apportionment from New Mexico to Texas, which has a lower statutory state tax rate than New Mexico. As such, we recognized an overall state deferred tax benefit of approximately $21 million for the year ended December 31, 2016.

Capital Commitments, Capital Resources and Liquidity

Capital commitments. Our primary needs for cash are development, exploration and acquisition of oil and natural gas assets, 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 years ended December 31, 2018, 2017 and 2016 totaled $2.6 billion, $1.7 billion and $1.2 billion, respectively. The increase was primarily due to our increased drilling and completion activity level during 2018 as compared to 2017 and 2016. Our intent is to manage our capital spending to be within our operating cash flow, excluding unbudgeted acquisitions. The primary reason for the differences in costs incurred and cash flow expenditures was the timing of payments. Total 2018 expenditures were primarily funded in part from cash flows from operations and proceeds from our January 2018 Delaware Basin divestitures.

2019 capital budget. In October 2018, our board of directors approved our 2019 capital budget of up to $3.8 billion. With current commodity prices, we expected to spend between $2.8 billion and $3.0 billion on drilling and completion activity.

2019 dividends. On February 19, 2019, our board of directors declared a cash dividend of $0.125 per share for the first quarter of 2019. The total cash dividend, including cash dividend on unvested restricted stock awards, of $25 million is expected to be paid on March 29, 2019 to stockholders of record as of March 1, 2019. We intend to continue to pay a quarterly dividend of $0.125 in the future, however, any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant.

Other than the customary purchase of leasehold acreage, our capital budgets are exclusive of acquisitions. We do not have a specific acquisition budget because the timing and size of acquisitions are difficult to forecast. We evaluate opportunities to purchase or sell oil and natural gas properties in the marketplace and could participate as a buyer or seller of properties at various times. We seek to acquire oil and natural gas properties that provide opportunities for the addition of reserves and production through a combination of development, high-potential exploration and control of operations that will allow us to apply our operating expertise, such as the RSP Acquisition.

Acquisitions. The following table reflects our expenditures for acquisitions of proved and unproved properties for the years ended December 31, 2018, 2017 and 2016:

	Years Ended December 31,		
(in millions)	**2018**	**2017**	**2016**
Property acquisition costs:			
Proved	$ 4,136	$ 303	$ 982
Unproved	3,617	905	1,154
Total property acquisition costs (a)	$ 7,753	$ 1,208	$ 2,136

(a) Included in the property acquisition costs above are budgeted unproved leasehold acreage acquisitions of approximately $51 million, $52 million and $30 million for the years ended December 31, 2018, 2017 and 2016, respectively. Our unbudgeted acquisitions during 2018 were primarily comprised of approximately $7.6 billion of property acquisition costs related to the RSP Acquisition. Our unbudgeted acquisitions during 2017 were primarily comprised of approximately $1.1 billion of property acquisition costs related to our Midland Basin and Delaware Basin acquisitions. Our unbudgeted acquisitions during 2016 were primarily comprised of approximately $2.1 billion of property acquisition costs related to the Reliance Acquisition and Delaware Basin acquisition.

Contractual obligations. We had the following contractual obligations at December 31, 2018:

		Payments Due by Period			
(in millions)	**Total**	**Less than 1 year**	**1 - 3 years**	**3 - 5 years**	**More than 5 years**
Long-term debt (a)	$ 4,242	$ -	$ -	$ 242	$ 4,000
Cash interest expense on debt (b)	2,991	256	372	354	2,009
Asset retirement obligations (c)	179	11	13	3	152
Employment agreements with officers (d)	9	9	-	-	-
Purchase obligations (e)	442	88	155	69	130
Operating lease obligations	40	14	22	3	1
Total contractual obligations (f)	$ 7,903	$ 378	$ 562	$ 671	$ 6,292

(a) See Note 10 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for information regarding future interest payment obligations on our long-term debt. The amounts included in the table above represent principal maturities only.

(b) Cash interest expense on our senior notes is estimated assuming no principal repayment until their maturity dates. Also included in the “Less than 1 year” column is accrued interest at December 31, 2018 of approximately $70 million. At December 31, 2018, we had variable-rate debt outstanding under our Credit Facility of $242 million.

(c) Amounts represent costs related to expected oil and natural gas property abandonments, net of any future accretion.

(d) Represents amounts of cash compensation we are obligated to pay to our officers under employment agreements assuming such employees continue to serve the entire term of their employment agreement and their cash compensation is not adjusted.

(e) Relates to purchase agreements we have entered into including daywork drilling contracts, water commitment agreements, throughput volume delivery commitments, fixed and variable power commitments, fixed asset commitments and maintenance commitments.

(f) The amounts above do not include the liability for unrecognized tax benefits. See Note 12 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information.

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 October 2018, our board of directors approved our 2019 capital budget of up to $3.8 billion. With current commodity prices, we expect to spend between $2.8 billion and $3.0 billion on drilling and completion activity.

The following table summarizes our changes in cash and cash equivalents for the years ended December 31, 2018, 2017 and 2016:

	Years Ended December 31,		
(in millions)	**2018**	**2017**	**2016**
Net cash provided by operating activities	$ 2,558	$ 1,695	$ 1,384
Net cash used in investing activities	(2,216)	(1,719)	(2,225)
Net cash provided by (used in) financing activities	(342)	(29)	665
Net decrease in cash and cash equivalents	$ -	$ (53)	$ (176)

Cash flow from operating activities. The increase in operating cash flows during the year ended December 31, 2018 as compared to 2017 was primarily due to an increase in oil and natural gas revenues of approximately $1.6 billion, partially offset by (i) a decrease in operating cash flow of approximately $297 million due to approximately $218 million for settlements paid on derivatives during the year ended December 31, 2018, as compared to approximately $79 million in settlements received from derivatives during 2017, (ii) approximately $182 million increase in production expense and (iii) approximately $106 million increase in production tax expense.

The increase in operating cash flows during the year ended December 31, 2017 as compared to 2016 was primarily due to an increase in oil and natural gas revenues of approximately $951 million and a decrease in cash interest expense of approximately $55 million, partially offset by (i) approximately $546 million decrease in settlements received from derivatives, (ii) approximately $88 million increase in production expense and (iii) approximately $68 million increase in production tax expense.

Our net cash provided by operating activities included a benefit of approximately $4 million, a reduction of approximately $23 million and a reduction of approximately $51 million for the years ended December 31, 2018, 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. Our investing activities consist primarily of drilling and completion activity, acquisitions and divestitures. The primary reason for the differences in costs incurred on oil and natural gas properties, including acquisitions, and cash flow expenditures is the timing of payments and the issuances of shares of common stock to fund certain acquisitions.

For the year ended December 31, 2018, our net cash used in investing activities was approximately $2.2 billion, which consisted primarily of our investment of approximately $2.5 billion for additions to oil and natural gas properties and approximately $136 million of oil and natural gas property acquisitions, partially offset by (i) approximately $361 million of proceeds received from the disposition of certain assets and (ii) a $148 million distribution received from Oryx, one of our equity method investments. The total distribution from Oryx was approximately $157 million, of which approximately $9 million represented cumulative Oryx earnings and was classified as cash flow from operating activities, while the remaining amount of approximately $148 million was classified as cash flow from investing activities. The 2018 expenditures were primarily funded with cash flows from operations.

For the year ended December 31, 2017, our net cash used in investing activities was approximately $1.7 billion, which consisted primarily of our investment of approximately $1.6 billion for additions to oil and natural gas properties and approximately $908 million of oil and natural gas property acquisitions. This was partially offset by approximately $803 million of proceeds received from the disposition of certain assets. The 2017 expenditures were primarily funded in part from (i) cash flows from operations, (ii) proceeds from our February 2017 divestiture of ACC and (iii) our issuance of approximately 2.2 million shares of common stock related to our Delaware Basin acquisition.

For the year ended December 31, 2016, our net cash used in investing activities was approximately $2.2 billion, which consisted primarily of our investment of approximately $1.0 billion for additions to oil and natural gas properties and approximately $1.4 billion of oil and natural gas property acquisitions. This was partially offset by approximately $332 million of proceeds received from the disposition of certain assets. The 2016 expenditures were funded in part from (i) proceeds from our February 2016 divestiture, (ii) our issuance of approximately 2.2 million shares of common stock related to our March 2016 acquisition, (iii) proceeds from our August 2016 equity offering and (iv) our issuance of approximately 3.9 million shares of common stock related to the Reliance Acquisition.

Cash flow from financing activities. For the year ended December 31, 2018, our net cash used in financing activities was approximately $342 million. In July 2018, we issued $1,600 million in aggregate principal amount of the Notes, for which we received net proceeds of approximately $1,579 million. We used the net proceeds to redeem and cancel the RSP Notes. We made aggregate payments of approximately $1.2 billion to redeem and cancel the RSP Notes, including make-whole call premiums of approximately $35 million and $33 million for the RSP 2022 Notes and the RSP 2025 Notes, respectively. We also paid accrued interest of approximately $14 million on the RSP Notes. The remaining proceeds, along with borrowings under our Credit Facility, were used to repay the $540 million of outstanding principal under RSP's revolving credit facility, including $1 million in accrued interest. We also made net payments of $80 million on our Credit Facility during 2018.

For the year ended December 31, 2017, our net cash used in financing activities was approximately $29 million. In September 2017, we issued $1,800 million in aggregate principal amount of the 2017 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 the 5.5% Notes at a price equal to 102.934 percent of par and (ii) redemption of our remaining obligations of the $918 million outstanding 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. We also had net borrowings of $322 million under our Credit Facility during 2017.

For the year ended December 31, 2016, our net cash provided by financing activities was approximately $665 million primarily due to the following activities:

- 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. We used a portion of the net proceeds to finance part of the cash portion of the purchase price for the Reliance Acquisition and to fund part of the early redemption of the 7.0% Notes and the remainder for general corporate purposes.

- In September 2016, we redeemed the $600 million outstanding principal amount of the 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 December 2016, we issued $600 million in aggregate principal amount of 4.375% senior notes due 2025 at par, for which we received net proceeds of approximately $593 million. We used the net proceeds from the offering to fund the satisfaction and discharge of our obligations under the indenture of the $600 million outstanding principal amount of the 6.5% Notes at a price equal to 103.25 percent of par. The early extinguishment price included the make-whole premium of $20 million.

In April 2017, we amended our Credit Facility to decrease our unused lender commitments. 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 our Credit Facility. If the Investment Grade Period under our Credit Facility terminates (whether automatically or by our election), our 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. At December 31, 2018, we had unused commitments under our Credit Facility of $1.8 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 (5.5 percent at December 31, 2018), (b) the federal funds effective rate plus 0.5 percent and (c) 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 and 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 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 the available borrowing capacity under our Credit Facility. At December 31, 2018, our commitments from our bank group were $2.0 billion of which $1.8 billion was unused commitments.

Debt ratings. We receive debt credit ratings from S&P, Moody's and Fitch and are designated as investment grade with all three agencies. In determining our ratings, the agencies perform regular reviews and 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.

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 under our Credit Facility will automatically terminate and cause our 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 Annual Report on Form 10-K, no changes in our credit ratings have occurred; 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 December 31, 2018 was $23.0 billion, consisting of debt of $4.2 billion and stockholders' equity of $18.8 billion. Our net book capitalization at December 31, 2017 was $11.6 billion, consisting of debt of $2.7 billion and stockholders' equity of $8.9 billion. Our ratio of net debt to net book capitalization was 18 percent and 23 percent at December 31, 2018 and 2017, respectively. Our ratio of current assets to current liabilities was 1.04 to 1.0 at December 31, 2018 as compared to 0.51 to 1.0 at December 31, 2017.

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 we are unable to control or predict. During the year ended December 31, 2018, we received an average of $56.22 per barrel of oil and $3.40 per Mcf of natural gas before consideration of commodity derivative contracts compared to $48.13 and $39.90 per barrel of oil and $3.07 and $2.23 per Mcf of natural gas in the years ended December 31, 2017 and 2016, respectively. 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 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 stock-based compensation, valuation of business combinations, accounting and valuation of nonmonetary transactions, goodwill impairment, litigation and environmental contingencies, valuation of financial derivative instruments, uncertain tax positions 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.

Successful Efforts Method of Accounting

We utilize the successful efforts method of accounting for our oil and natural gas exploration and development activities. Under this method, exploration expenses, including geological and geophysical costs, lease rentals and exploratory dry holes, are charged against income as incurred. Costs of successful wells and related production equipment, undeveloped leases and developmental dry holes are capitalized. Exploratory drilling costs are initially capitalized, but are charged to expense if and when a well is determined not to have found proved reserves. Generally, a gain or loss is recognized when producing fields are sold. This accounting method may yield significantly different results than the full cost method of accounting.

The application of the successful efforts method of accounting requires management's judgment to determine the proper designation of wells as either developmental or exploratory, which will ultimately determine the proper accounting treatment of costs of dry holes. Once a well is drilled, the determination that proved reserves have been discovered may take considerable time, and requires both judgment and application of industry experience. The evaluation of oil and natural gas leasehold acquisition costs included in unproved properties requires management's judgment to estimate the fair value of such properties. Drilling activities in an area by other companies may also effectively impair our leasehold positions.

Depletion of capitalized drilling and development costs of oil and natural gas properties is computed using the unit-of-production method on total estimated proved developed oil and natural gas reserves. Depletion of producing leaseholds is based on the unit-of-production method using our total estimated proved reserves. In arriving at rates under the unit-of-production method, the quantities of recoverable oil and natural gas are established based on estimates made by our geologists and engineers and independent engineers. Service properties, equipment and other assets are depreciated using the straight-line method over estimated useful lives of two to 39 years.

Oil and Natural Gas Reserves and Standardized Measure of Discounted Net Future Cash Flows

This report presents estimates of our proved reserves as of December 31, 2018, which have been prepared and presented in accordance with SEC guidelines. The pricing that was used for estimates of our reserves as of December 31, 2018 was based on the 12-month unweighted average of the first-day-of-the-month WTI posted price of $62.04 per Bbl for oil and Henry Hub spot natural gas price of $3.10 per MMBtu for natural gas.

Our independent engineers and technical staff prepare the estimates of our oil and natural gas reserves and associated future net cash flows. Even though our independent engineers and technical staff are knowledgeable and follow authoritative guidelines for estimating reserves, they must make a number of subjective assumptions based on professional judgments in developing the reserve estimates. Reserve estimates are updated at least annually and consider recent production levels and other technical information about each field. Periodic revisions to the estimated reserves and future net cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, oil and natural gas prices, cost changes, technological advances, new geological or geophysical data, or other economic factors. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly alter future depletion and result in impairment of long-lived assets that may be material.

It should not be assumed that the Standardized Measure included in this report as of December 31, 2018 is the current market value of our estimated proved reserves. In accordance with SEC requirements, we based the 2018 Standardized Measure on the 12-month unweighted average of the first-day-of-the-month pricing for oil and natural gas and prevailing costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs utilized in the estimate. See “Item 1A. Risk Factors” and “Item 2. Properties” for additional information regarding estimates of proved reserves.

Our estimates of proved reserves materially impact depletion expense. If the estimates of proved reserves decline, the rate at which we record depletion expense will increase, reducing future earnings. Such a decline may result from lower commodity prices, which may make it uneconomical to drill for and produce higher cost fields. In addition, a decline in proved reserve estimates may impact the outcome of our assessment of our proved properties for impairment.

Asset Retirement Obligations

There are legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and the normal operation of a long-lived asset. The primary impact of this relates to oil and natural gas wells on which we have a legal obligation to plug and abandon. We record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and, generally, a corresponding increase in the carrying amount of the related long-lived asset. The determination of the fair value of the liability requires us to make numerous judgments and estimates, including judgments and estimates related to future costs to plug and abandon wells, future inflation rates and estimated lives of the related assets. When the judgments used to estimate the initial fair value of the asset retirement obligation change, an adjustment is recorded to both the obligation and the carrying amount of the related long-lived asset. Historically, there have been no significant revisions to our initial estimates once future results became known. See Note 6 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding our asset retirement obligations.

Impairment of Long-Lived Assets

All of our long-lived assets are monitored for potential impairment when circumstances indicate that the carrying value of an asset may be greater than management's estimates of its future net cash flows, including cash flows from proved reserves, risk-adjusted probable and possible reserves, and integrated assets. If the carrying value of the long-lived assets exceeds the sum of estimated undiscounted future net cash flows, an impairment loss is recognized for the difference between the estimated fair value and the carrying value of the assets. The evaluations involve a significant amount of judgment since the results are based on estimated future events, such as future sales prices for oil and natural gas, future costs to produce these products, estimates of future oil and natural gas reserves to be recovered and the timing thereof, the economic and regulatory climates, cash flows from integrated assets and other factors. The need to test an asset for impairment may result from significant declines in sales prices or downward revisions in estimated quantities of oil and natural gas reserves. Any assets held for sale are reviewed for impairment when we approve the plan to sell. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. At December 31, 2018, our estimates of commodity prices for purposes of determining undiscounted future cash flows, which are based on the NYMEX strip, ranged from a 2019 price of $47.09 per barrel of oil increasing to a 2025 price of $53.10 per barrel of oil. Natural gas prices ranged from a 2019 price of $2.78 per Mcf of natural gas decreasing to a 2021 price of $2.61 per Mcf then rising to a 2025 price of $2.90 per Mcf of natural gas. Both oil and natural gas commodity prices for this purpose were held flat after 2025. We did not recognize an impairment charge during the year ended December 31, 2018.

It is reasonably possible that the estimates of undiscounted future net cash flows of our long-lived assets may change in the future resulting in the need to impair carrying values. 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 December 31, 2018 with no other changes in capital costs, operating costs, price differentials or reserve performance curves, the carrying amount of our Yeso field would have exceeded the expected undiscounted future net cash flow and an impairment of approximately $800 million would have been recorded. The impairment would have been the result of certain downward revisions to our proved reserves in the Yeso field during 2018. 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 or will not 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. See Notes 2 and 8 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information on impairments of long-lived assets.

Unproved oil and natural gas properties are periodically assessed for impairment by considering future drilling and exploration plans, results of exploration activities, commodity price outlooks, planned future sales and expiration of all or a portion of the projects. During the years ended December 31, 2018, 2017 and 2016, we recognized expense of approximately $35 million, $27 million and $50 million, respectively, related to abandoned and expiring acreage, which is included in exploration and abandonments expense in the accompanying consolidated statements of operations.

Valuation of Stock-Based Compensation

In accordance with GAAP, we calculate the fair value of stock-based compensation using various valuation methods. The valuation methods require the use of estimates to derive the inputs necessary to determine fair value. We utilize (i) the average of the high and low stock price on the date of grant for the fair value of restricted stock awards and (ii) the Monte Carlo simulation method for the fair value of performance unit awards. The significant assumptions used in these models include expected volatility, expected term, risk-free interest rate, forfeiture rate, and the probability of meeting performance targets. Each of these valuation methods were chosen as management believes they give the best estimate of fair value for the respective stock-based awards. See Note 7 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information regarding our stock-based compensation.

Valuation of Business Combinations

In connection with a purchase business combination, the acquiring company must record assets acquired and liabilities assumed based on fair values as of the acquisition date. Deferred taxes must be recorded for any differences between the assigned values and tax bases of assets and liabilities. Any excess of purchase price over amounts assigned to assets and liabilities is recorded as goodwill. The amount of goodwill recorded in any particular business combination can vary significantly depending upon the value attributed to assets acquired and liabilities assumed.

In estimating the fair values of assets acquired and liabilities assumed, we make various assumptions. The most significant assumptions related to the estimated fair values assigned to proved and unproved oil and natural gas properties and integrated assets. To estimate the fair values of these properties, we utilize estimates of oil and natural gas reserves. We make future price assumptions to apply to the estimated reserves quantities acquired and estimate future operating and development costs to arrive at estimates of future net cash flows. For estimated proved reserves, the future net cash flows are discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the acquisition. The market-based weighted average cost of capital rate is subject to additional project-specific risking factors. To estimate the fair value of unproved properties, we apply risk-weighting factors of the future net cash flows of unproved reserves, or we may evaluate acreage values through recent market transactions in the area.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. A higher fair value assigned to a property results in a higher depletion expense, which results in lower net earnings. Fair values are based on estimates of future commodity prices, reserves quantities, operating expenses and development costs. This increases the likelihood of impairment if future commodity prices or reserves quantities are lower than those originally used to determine fair value or if future operating expenses or development costs are higher than those originally used to determine fair value. Impairment would have no effect on cash flows but would result in a decrease in net income for the period in which the impairment is recorded. Historically, we have had no material revisions to valuations of business combinations once the valuation estimate was finalized.

Accounting and Valuation of Nonmonetary Transactions

In connection with nonmonetary transactions, which include exchanges of producing and non-producing assets, we must evaluate the transaction to determine appropriate accounting treatment. In general, the basic principle of accounting for nonmonetary transactions is based on the fair values involved, which is the same basis used in monetary transactions and results in the recognition of gains and losses. However, certain nonmonetary transactions meet criteria that require modification of the basic principle that necessitate recording values based on historical book value. We determine the treatment of nonmonetary transactions based on the individual facts and circumstances of each transaction. In cases where

nonmonetary transactions are recorded at fair value, we make various assumptions. The most significant assumptions are related to the estimated fair values assigned to proved and unproved oil and natural gas properties, similar to our valuation of the fair value of oil and natural gas assets acquired during a business combination described above. Any resulting difference between the fair value of the assets involved and their carrying value is recorded as a gain or loss in the consolidated statement of operations.

Estimated fair values assigned to assets exchanged can have a significant effect on our results of operations in the future. If future commodity prices or reserves quantities are lower than those originally used to determine fair value or if future operating expenses or development costs are higher than those originally used to determine fair value, we would record an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value. Impairment would have no effect on cash flows but would result in a decrease in net income for the period in which the impairment is recorded.

Goodwill Impairment

Goodwill is not amortized but assessed for impairment on an annual basis, or more frequently if indicators of impairment exist. Impairment tests, which involve the use of estimates related to the fair market value of the business operations with which goodwill is associated, is performed as of July 1 of each year. As we operate as a single operating segment and a single reporting unit, we evaluate goodwill for impairment based on an evaluation of the fair value of the company as a whole. There is considerable judgment involved in estimating fair values, including, among other things, determining the control premium when using the market approach in determining the fair value. To establish a reasonable control premium, we consider the premiums paid in recent market acquisitions and analyze current industry, market and economic conditions along with other factors or available information specific to our business. See Notes 2 and 4 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information regarding goodwill.

Litigation and Environmental Contingencies

We make judgments and estimates in recording liabilities for ongoing litigation and environmental remediation. Actual costs can vary from such estimates for a variety of reasons. The costs to settle litigation can vary from estimates based on differing interpretations of laws and opinions and assessments on the amount of damages. Similarly, environmental remediation liabilities are subject to change because of changes in laws and regulations, developing information relating to the extent and nature of site contamination and improvements in technology. A liability is recorded for these types of contingencies if we determine the loss to be both probable and reasonably estimable. If we are unable to reasonably estimate an amount but we are able to estimate a range of reasonably possible amounts, then the low end of the range is recorded. See Note 11 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for more information regarding our commitments and contingencies.

Valuation of Financial Derivatives

In order to reduce commodity price uncertainty and increase cash flow predictability relating to the marketing of our oil and natural gas, we enter into commodity price hedging arrangements with respect to a portion of our expected production. In addition, we have used derivative instruments in connection with acquisitions and certain price-sensitive projects. Management exercises significant judgment in determining the types of instruments to be used, production volumes to be hedged, prices at which to hedge and the counterparties' creditworthiness. All derivative instruments are reflected at fair value in our consolidated balance sheets.

Our open commodity derivative instruments were in a net asset position with a fair value of $695 million at December 31, 2018. In order to determine the fair value at the end of each reporting period, we compute discounted cash flows for the duration of each commodity derivative instrument using the terms of the related contract. Inputs consist of published forward commodity price curves as of the date of the estimate. We compare these prices to the price parameters contained in our hedge contracts to determine estimated future cash inflows or outflows. We then discount the cash inflows or outflows using a combination of published LIBOR rates and Eurodollar futures rates. The fair values of our commodity derivative assets and liabilities include a measure of credit risk based on average published yields by credit rating.

Changes in the fair values of our commodity derivative instruments have a significant impact on our net income because we follow mark-to-market accounting and recognize all gains and losses on such instruments in earnings in the period in which they occur. For the year ended December 31, 2018, we reported a $832 million gain on commodity derivative instruments.

We compare our estimates of the fair values of our commodity derivative instruments with those provided by our counterparties. There have been no significant differences.

Income Taxes

On December 22, 2017, the President of the United States signed the TCJA into law, which enacted significant changes to the federal income tax laws. According to ASC 740, "Income Taxes," a company is required to record the effects of an enacted tax law or rate change in the period of enactment. Based on the comprehensiveness of TCJA and the challenges faced by calendar year-end registrants to complete the accounting for the income tax effects of the TCJA in the period of enactment, the SEC issued SAB 118 “Income Tax Accounting Implications of the Tax Cuts and Jobs Act,” which allowed companies to report provisional amounts when based on reasonable estimates and to adjust these amounts during a measurement period of up to one year.

We elected to apply SAB 118 and recorded provisional amounts of our income tax balances in our consolidated financial statements at December 31, 2017. We calculated our best estimate of the impact of the TCJA, including the federal statutory tax rate change noted below, in our 2017 income tax provision in accordance with our understanding of the TCJA and recorded a $398 million decrease to our income tax provision at December 31, 2017. The provisional amount related to the re-measurement of certain deferred tax assets and liabilities based on the rates at which they are expected to reverse in the future. At December 31, 2018, the Company completed its accounting for all of the enactment-date tax effects of the TCJA and recognized an adjustment of $7 million to the provisional amount recorded at December 31, 2017. This adjustment was primarily related to the deductibility of certain performance-based compensation based on additional available regulatory and interpretive guidance.

On July 19, 2018, we completed the RSP Acquisition. For federal income tax purposes, the transaction qualified as a tax-free merger whereby we acquired carryover tax basis in RSP’s assets and liabilities. As of December 31, 2018, we recorded an opening balance sheet deferred tax liability of $515 million based on our assessment of the carryover tax basis, which includes a deferred tax asset related to tax attributes acquired from RSP. The acquired income tax attributes primarily consist of NOLs and research and development credits that are subject to an annual limitation under Internal Revenue Code Section 382. The Company expects that these tax attributes will be fully utilized prior to expiration.

Our provision for income taxes includes both federal and state taxes of the jurisdictions in which we operate. We estimate our overall tax rate using a combination of the enacted federal statutory tax rate, which decreased from 35 percent to 21 percent effective January 1, 2018 as a result of the TCJA, and a blend of enacted state tax rates. Acquisitions or dispositions of assets and changes in our drilling plan by tax jurisdiction could change the apportionment of our state taxes, which would impact our overall tax rate.

We recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based upon the technical merits of the position. At December 31, 2018, we had unrecognized tax benefits of approximately $63 million, primarily related to research and development credits. If all or a portion of the unrecognized tax benefit is sustained upon examination by the taxing authorities, the tax benefit will be recognized as a reduction to our deferred tax liability and will affect our effective tax rate in the period it is recognized. The assessment of potential uncertain tax positions requires a significant amount of judgment and are reviewed and adjusted on a periodic basis.

Valuation of Financial Derivatives

Our federal and state income tax returns are not prepared or filed before the consolidated financial statements are prepared; therefore, we estimate the tax basis of our assets and liabilities, which are based on numerous judgments and assumptions inherent in the determination of future taxable income, at the end of each period as well as the effects of tax rate changes and tax credits. Adjustments related to these estimates are recorded in our tax provision in the period in which we finalize our income tax returns. Historically, we have had no significant changes as a result of filing our tax returns. Material changes to our tax accruals and uncertain tax positions may occur in the future based on audits, changes in legislation or resolution of pending matters.

See Note 12 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding our current year income tax expense, deferred tax balances and uncertain tax positions.

New accounting pronouncements issued but not yet adopted. See Note 2 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for information regarding new accounting pronouncements issued but not yet adopted.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to a variety of market risks, including credit risk, commodity price risk and interest rate risk. We address these risks through a program of risk management which includes the use of derivative instruments. The following quantitative and qualitative information is provided about financial instruments to which we are a party at December 31, 2018, 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 International Swap Dealers Association Master Agreements ("ISDA Agreements") with each of our derivative counterparties. The terms of the ISDA Agreements provide us and the counterparties with rights of set-off upon the occurrence of defined acts of default by either us or a counterparty to a derivative, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party. See Note 9 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding our derivative activities.

Commodity price risk*.* We are exposed to market risk as the prices of 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 our earnings. 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 average commodity prices for the years ended December 31, 2018 and 2017:

	2018		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**	**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	$ (369)	$ 370	$ (290)	$ 290
Natural gas derivatives	(37)	37	(37)	37
Total	$ (406)	$ 407	$ (327)	$ 327

Our commodity price risk management arrangements expose us to risk of non-performance by the counterparty to the agreements. Our exposure to the risk of non-performance is diversified over large, investment grade financial institutions. In addition, we have master netting agreements with the counterparties that allow for offsetting payables against receivables from separate contracts with the same counterparty. At December 31, 2018, the counterparties to our commodity price risk management arrangements include fourteen financial institutions, the majority of which are lenders under our Credit Facility. Risk of non-performance is considered when determining the fair value of our commodity price risk management arrangements. The fair value adjustment for non-performance risk was immaterial at December 31, 2018. If at any point a counterparty's financial position deteriorates, such deterioration could have a significant impact on the collectability of that counterparty's related commodity price risk management arrangement asset. See Note 13 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding our significant derivative counterparties.

At December 31, 2018, we had (i) oil price swaps and oil costless collars covering future oil production from January 1, 2019 through December 31, 2020 and (ii) oil basis swaps covering our Midland to Cushing basis differential from January 1, 2019 to December 31, 2021. The NYMEX oil price at December 31, 2018 was $45.41 per Bbl. At February 15, 2019, the NYMEX oil price was $55.59 per Bbl.

At December 31, 2018, we had natural gas price swaps that settle on a monthly basis covering future natural gas production from January 1, 2019 to December 31, 2020. The NYMEX natural gas price at December 31, 2018 was $2.94 per MMBtu. At February 15, 2019, the NYMEX natural gas price was $2.63 per MMBtu. See Note 9 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information on our commodity derivative instruments.

A decrease in the average forward NYMEX oil and natural gas prices below those at December 31, 2018 would increase the fair value asset of our commodity derivative contracts from their recorded balances at December 31, 2018. Changes in the recorded fair value of our commodity derivative contracts are marked to market through earnings as gains or losses. The potential increase in our fair value asset would be recorded in earnings as a gain. However, an increase in the average forward NYMEX oil and natural gas prices above those at December 31, 2018 would decrease the fair value asset of our commodity derivative contracts from their recorded balances at December 31, 2018. The potential decrease in our fair value asset 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.

We recorded a gain on derivatives of $832 million for the year ended December 31, 2018, compared to a loss of $126 million for the year ended December 31, 2017. The largest factor in the change from 2017 to 2018 related to the change in commodity future price curves at the respective measurement and settlement periods.

The fair value of our derivative instruments is determined based on our valuation models. We did not change our valuation method during the year ended December 31, 2018. See Note 9 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding our derivative instruments. The following table reconciles the changes that occurred in the fair values of our derivative instruments during the year ended December 31, 2018:

(in millions)		**Commodity Derivative Instruments Net Assets**
Fair value of contracts outstanding at December 31, 2017	$	(379)
Changes in fair values (a)		832
Contract maturities		218
Fair value of RSP contracts acquired		24
Fair value of contracts outstanding at December 31, 2018 (b)	$	695

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

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

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 had no outstanding interest rate derivative contracts at December 31, 2018. 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 $242 million outstanding under our Credit Facility at December 31, 2018. The impact of a one percent increase in interest rates on this amount of debt would result in increased annual interest expense of approximately $2 million.

Item 8. Financial Statements and Supplementary Data

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Financial Statements of Concho Resources Inc.:

73

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders

Concho Resources Inc.

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Concho Resources Inc. (a Delaware corporation) and subsidiaries (the “Company”) as of December 31, 2018 and 2017, the related consolidated statements of operations, changes in stockholders’ equity, and cash flows for each of the three years in the period ended December 31, 2018, and the related notes (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (“PCAOB”), the Company’s internal control over financial reporting as of December 31, 2018, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”), and our report dated February 20, 2019 expressed an unqualified opinion.

Basis for opinion

These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2004.

Oklahoma City, Oklahoma

February 20, 2019

GLOSSARY OF TERMS

The following terms are used throughout this report:

Bbl One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to oil, condensate or natural gas liquids.

Bcf One billion cubic feet of natural gas.

Boe One barrel of oil equivalent, a standard convention used to express oil and natural gas volumes on a comparable oil equivalent basis. Natural gas equivalents are determined under the relative energy content method by using the ratio of 6.0 Mcf of natural gas to 1.0 Bbl of oil or condensate.

Basin A large natural depression on the earth's surface in which sediments accumulate.

Development wells Wells drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed production expenses, taxes and the royalty burden.

Exploratory wells Wells drilled to find and produce oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir, or to extend a known reservoir.

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

GAAP Generally Accepted Accounting Principles in the United States of America.

Gross wells The number of wells in which a working interest is owned.

Horizontal drilling A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a high angle to vertical (which can be greater than 90 degrees) in order to stay within a specified interval.

Infill drilling Drilling into the same pool as known producing wells so that oil or natural gas does not have to travel as far through the formation.

LIBOR London Interbank Offered Rate, which is a market rate of interest.

MBbl One thousand barrels of oil, condensate or natural gas liquids.

MBoe One thousand Boe.

Mcf One thousand cubic feet of natural gas.

MMBoe One million Boe.

MMBtu One million British thermal units.

MMcf	One million cubic feet of natural gas.
NYMEX	The New York Mercantile Exchange.
NYSE	The New York Stock Exchange.

Net acres The percentage of total acres an owner owns out of a particular number of acres within a specified tract. For example, an owner who has a 50 percent interest in 100 acres owns 50 net acres.

Net wells The total of fractional working interests owned in gross wells.

PV-10 When used with respect to oil and natural gas reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses except for specific general and administrative expenses incurred to operate the properties, discounted to a present value using an annual discount rate of 10 percent. PV-10 is a non-GAAP financial measure.

Productive wells Wells that produce commercial quantities of hydrocarbons, exclusive of their capacity to produce at a reasonable rate of return.

Proved developed reserves Proved developed reserves are proved reserves that can be expected to be recovered:

(i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) through installed extraction equipment and infrastructure operational at the time of the reserve estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Proved Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Proved Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Proved reserves Proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) the area identified by drilling and limited by fluid contacts, if any, and

(B) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons ("LKH") as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil ("HKO") elevation and the potential exists for an associated natural gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) the project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved undeveloped reserves Proved undeveloped oil and natural gas reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years from initial booking, unless the specific circumstances justify a longer time.

Recompletion The addition of production from another interval or formation in an existing wellbore.

Reservoir A formation beneath the surface of the earth from which hydrocarbons may be present. Its make-up is sufficiently homogenous to differentiate it from other formations.

Spacing The distance between wells producing from the same reservoir. Spacing is expressed in terms of acres, e.g., 40-acre spacing, and is established by regulatory agencies.

Standardized Measure The present value (discounted at an annual rate of 10 percent) of estimated future net revenues to be generated from the production of proved reserves net of estimated income taxes associated with such net revenues, as determined in accordance with FASB guidelines, without giving effect to non-property related expenses such as indirect general and administrative expenses, and debt service or to depreciation, depletion and amortization. Standardized measure does not give effect to derivative transactions.

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

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

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

Workover Operations on a producing well to restore or increase production.

WTI West Texas Intermediate - light, sweet blend of oil produced from fields in western Texas.

Concho Resources Inc.

Consolidated Balance Sheets

(in millions, except share and per share amounts)	December 31, 2018	2017
Assets		
Current assets:		
Cash and cash equivalents	$ -	$ -
Accounts receivable, net of allowance for doubtful accounts:		
Oil and natural gas	466	331
Joint operations and other	365	212
Inventory	35	14
Derivative instruments	484	-
Prepaid costs and other	59	35
Total current assets	1,409	592
Property and equipment:		
Oil and natural gas properties, successful efforts method	31,706	21,267
Accumulated depletion and depreciation	(9,701)	(8,460)
Total oil and natural gas properties, net	22,005	12,807
Other property and equipment, net	308	234
Total property and equipment, net	22,313	13,041
Deferred loan costs, net	10	13
Goodwill	2,224	-
Intangible assets, net	19	26
Noncurrent derivative instruments	211	-
Other assets	108	60
Total assets	$ 26,294	$ 13,732
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable - trade	$ 50	$ 43
Bank overdrafts	159	116
Revenue payable	253	183
Accrued drilling costs	574	330
Derivative instruments	-	277
Other current liabilities	320	216
Total current liabilities	1,356	1,165
Long-term debt	4,194	2,691
Deferred income taxes	1,808	687
Noncurrent derivative instruments	-	102
Asset retirement obligations and other long-term liabilities	168	172
Commitments and contingencies (Note 11)		
Stockholders' equity:		
Common stock, $0.001 par value; 300,000,000 authorized; 201,288,884 and 149,324,849		

shares issued at December 31, 2018 and 2017, respectively		-		-
Additional paid-in capital		14,773		7,142
Retained earnings		4,126		1,840
Treasury stock, at cost; 1,031,655 and 598,049 shares at December 31, 2018 and 2017, respectively		(131)		(67)
Total stockholders' equity		18,768		8,915
Total liabilities and stockholders' equity	$	26,294	$	13,732

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

Concho Resources Inc.

Consolidated Statements of Operations

(in millions, except per share amounts)	**Years Ended December 31, 2018**	**2017**	**2016**
Operating revenues:			
Oil sales	$ 3,443	$ 2,092	$ 1,350
Natural gas sales	708	494	285
Total operating revenues	4,151	2,586	1,635
Operating costs and expenses:			
Oil and natural gas production	590	408	320
Production and ad valorem taxes	305	199	131
Gathering, processing and transportation	55	-	-
Exploration and abandonments	65	59	77
Depreciation, depletion and amortization	1,478	1,146	1,167
Accretion of discount on asset retirement obligations	10	8	7
Impairments of long-lived assets	-	-	1,525
General and administrative (including non-cash stock-based compensation of $82, $60 and $59 for the years ended December 31, 2018, 2017 and 2016, respectively)	311	244	226
(Gain) loss on derivatives	(832)	126	369
Gain on disposition of assets, net	(800)	(678)	(118)
Transaction costs	39	3	5
Total operating costs and expenses	1,221	1,515	3,709
Income (loss) from operations	2,930	1,071	(2,074)
Other income (expense):			
Interest expense	(149)	(146)	(204)
Loss on extinguishment of debt	-	(66)	(56)
Other, net	108	22	(4)
Total other expense	(41)	(190)	(264)
Income (loss) before income taxes	2,889	881	(2,338)
Income tax (expense) benefit	(603)	75	876
Net income (loss)	$ 2,286	$ 956	$ (1,462)
Earnings per share:			
Basic net income (loss)	$ 13.28	$ 6.44	$ (10.85)
Diluted net income (loss)	$ 13.25	$ 6.41	$ (10.85)

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

Concho Resources Inc.

Consolidated Statements of Stockholders' Equity

(in millions, except share data)	Common Stock Issued		Additional Paid-in	Retained	Treasury Stock		Total Stockholders'
	Shares (in thousands)	Amount	Capital	Earnings	Shares (in thousands)	Amount	Equity
BALANCE AT JANUARY 1, 2016	129,444	$ -	$ 4,629	$ 2,346	306	$ (32)	$ 6,943
Net loss	-	-	-	(1,462)	-	-	(1,462)
Issuance of common stock	10,350	-	1,327	-	-	-	1,327
Common stock issued in business combinations	6,134	-	768	-	-	-	768
Stock options exercised	23	-	1	-	-	-	1
Grants of restricted stock	451	-	-	-	-	-	-
Performance unit share conversion	180	-	-	-	-	-	-
Cancellation of restricted stock	(93)	-	-	-	-	-	-
Stock-based compensation	-	-	59	-	-	-	59
Tax deficiency related to stock-based compensation	-	-	(1)	-	-	-	(1)
Purchase of treasury stock	-	-	-	-	124	(12)	(12)
BALANCE AT DECEMBER 31, 2016	146,489	-	6,783	884	430	(44)	7,623
Adoption of ASU 2016-09 (Note 2)	-	-	8	-	-	-	8
BALANCE AT JANUARY 1, 2017	146,489	-	6,791	884	430	(44)	7,631
Net income	-	-	-	956	-	-	956
Common stock issued in business combinations	2,177	-	291	-	-	-	291
Stock options exercised	20	-	-	-	-	-	-
Grants of restricted stock	490	-	-	-	-	-	-
Performance unit share conversion	249	-	-	-	-	-	-
Cancellation of restricted stock	(100)	-	-	-	-	-	-
Stock-based compensation	-	-	60	-	-	-	60
Purchase of treasury stock	-	-	-	-	168	(23)	(23)
BALANCE AT DECEMBER 31, 2017	149,325	-	7,142	1,840	598	(67)	8,915
Net income	-	-	-	2,286	-	-	2,286
	50,915	-	7,549	-	-	-	7,549

Common stock issued in business combination							
Grants of restricted stock	687	-	-	-	-	-	-
Performance unit share conversion	447	-	-	-	-	-	-
Cancellation of restricted stock	(85)	-	-	-	-	-	-
Stock-based compensation	-	-	82	-	-	-	82
Purchase of treasury stock	-	-	-	-	434	(64)	(64)
BALANCE AT DECEMBER 31, 2018	201,289	$ -	$ 14,773	$ 4,126	1,032	$ (131)	$ 18,768

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

Concho Resources Inc.

Consolidated Statements of Cash Flows

	Years Ended December 31,		
(in millions)	**2018**	**2017**	**2016**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 2,286	$ 956	$ (1,462)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	1,478	1,146	1,167
Accretion of discount on asset retirement obligations	10	8	7
Impairments of long-lived assets	-	-	1,525
Exploration and abandonments, including dry holes	35	27	57
Non-cash stock-based compensation expense	82	60	59
Deferred income taxes	605	(71)	(864)
Gain on disposition of assets, net	(800)	(678)	(118)
(Gain) loss on derivatives	(832)	126	369
Net settlements received from (paid on) derivatives	(218)	79	625
Loss on extinguishment of debt	-	66	56
Other	(92)	(1)	14
Changes in operating assets and liabilities, net of acquisitions and dispositions:			
Accounts receivable	(35)	(126)	32
Prepaid costs and other	(10)	(9)	6
Inventory	(12)	-	2
Accounts payable	1	14	15
Revenue payable	52	52	(38)
Other current liabilities	8	46	(68)
Net cash provided by operating activities	2,558	1,695	1,384
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to oil and natural gas properties	(2,496)	(1,581)	(1,046)
Acquisitions of oil and natural gas properties	(136)	(908)	(1,351)
Additions to property, equipment and other assets	(90)	(44)	(61)
Proceeds from the disposition of assets	361	803	332
Deposits on dispositions of oil and natural gas properties	-	29	-
Direct transaction costs for disposition of assets	(3)	(18)	-
Funds held in escrow	-	-	(43)
Contributions to equity method investments	-	-	(56)
Distribution from equity method investment	148	-	-
Net cash used in investing activities	(2,216)	(1,719)	(2,225)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings under credit facility	3,316	1,001	-
Payments on credit facility	(3,396)	(679)	-
Issuance of senior notes, net	1,595	1,794	600
Repayments of senior notes	-	(2,150)	(1,200)
Repayments of RSP debt	(1,690)	-	-

Debt extinguishment costs		(83)		(63)		(42)
Excess tax deficiency from stock-based compensation		-		-		(1)
Net proceeds from issuance of common stock		-		-		1,327
Payments for loan costs		(16)		(25)		(7)
Purchase of treasury stock		(64)		(23)		(12)
Increase (decrease) in bank overdrafts		(4)		116		-
Net cash provided by (used in) financing activities		(342)		(29)		665
Net decrease in cash and cash equivalents		-		(53)		(176)
Cash and cash equivalents at beginning of period		-		53		229
Cash and cash equivalents at end of period	$	-	$	-	$	53
SUPPLEMENTAL CASH FLOWS:						
Cash paid for interest	$	118	$	139	$	232
Cash paid for income taxes	$	2	$	13	$	-
NON-CASH INVESTING AND FINANCING ACTIVITIES:						
Issuance of common stock for business combinations	$	7,549	$	291	$	768

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

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

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 consolidated financial statements also included the accounts of a variable interest entity (“VIE”) where the Company was the primary beneficiary of the arrangements until the VIE structure dissolved in January 2018. See Note 5 for additional information regarding the circumstances surrounding the VIE. The Company consolidates the financial statements of these entities. All material intercompany balances and transactions have been eliminated.

Reclassifications. Certain prior period amounts have been reclassified to conform to the 2018 presentation. These reclassifications had no impact on net income (loss), total assets, liabilities and stockholders’ equity or total cash flows.

Use of estimates in the preparation of financial statements. Preparation of financial statements in conformity with GAAP 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, goodwill, fair value of stock-based compensation, fair value of business combinations, fair value of nonmonetary transactions, fair value of derivative financial instruments and income taxes.

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 may 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.

Accounts receivable. The Company sells oil and natural gas to various customers and participates with other parties in the drilling, completion and operation of oil and natural gas wells. Oil and natural gas sales receivables related to these operations are generally unsecured. Joint interest receivables are generally secured pursuant to the operating agreement between or among the co-owners of the operated property. The Company determines joint interest operations accounts receivable allowances based on management’s assessment of the creditworthiness of the joint interest owners and the Company’s ability to realize the receivables through netting of anticipated future production revenues. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been exhausted. The Company had an allowance for doubtful accounts of approximately $5 million and $1 million for the years ended December 31, 2018 and 2017, respectively.

Inventory. Inventory consists primarily of tubular goods, water and other oilfield equipment that the Company plans to utilize in its ongoing exploration and development activities and is carried at the lower of weighted average cost or net realizable value.

Oil and natural gas properties. The Company utilizes the successful efforts method of accounting for its oil and natural gas properties. Under this method all costs associated with productive wells and nonproductive development wells are capitalized, while nonproductive exploration costs are expensed. Capitalized leasehold costs relating to proved properties are depleted using the unit-of-production method based on proved reserves. The depletion of capitalized drilling and development costs and integrated assets is based on the unit-of-production method using proved developed reserves. The Company recognized depletion expense of $1.5 billion, $1.1 billion and $1.1 billion during the years ended December 31, 2018, 2017 and 2016, respectively.

The Company generally does not carry the costs of drilling an exploratory well as an asset in its consolidated balance sheets following the completion of drilling unless both of the following conditions are met:

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

(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.

Due to the Company's large multi-well project development program, capital intensive nature and geographical location of certain projects, it may take longer than one year to evaluate the future potential of the exploration well and economics associated with making a determination on its commercial viability. In these instances, the project's feasibility is not contingent upon price improvements or advances in technology, but rather the Company's ongoing efforts and expenditures related to accurately predicting the hydrocarbon recoverability based on well information, gaining access to other companies' production, transportation or processing facilities and/or getting partner approval to drill additional appraisal wells. The Company's assessment of suspended exploratory well costs is continuous until a decision can be made that the well has found proved reserves and is transferred to proved oil and natural gas properties or is noncommercial and is charged to exploration and abandonments expense. See Note 3 for additional information regarding the Company's exploratory well costs.

Proceeds from the sales of individual properties and the capitalized costs of individual properties sold or abandoned are credited and charged, respectively, to accumulated depletion. Generally, no gain or loss is recognized until the entire depletion base is sold. However, gain or loss is recognized from the sale of less than an entire depletion base if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the depletion base. Ordinary maintenance and repair costs are expensed as incurred.

Costs of significant nonproducing properties, wells in the process of being drilled and completed and development projects are excluded from depletion until the related project is completed. The Company capitalizes interest on expenditures for significant development projects until such projects are ready for their intended use. During the years ended December 31, 2018 and 2017, the Company had capitalized interest of approximately $9 million and $3 million, respectively. The Company did not have capitalized interest related to significant oil and natural gas development projects for the year ended December 31, 2016.

The Company reviews its long-lived assets to be held and used, including proved oil and natural gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss is indicated if the sum of the expected future cash flows is less than the carrying amount of the assets. In this circumstance, the Company 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 reviews its oil and natural gas properties by depletion base. For each property determined to be impaired, an impairment loss equal to the difference between the carrying value of the properties and the estimated fair value (discounted future cash flows) of the properties and integrated assets would be recognized at that time. Estimating future cash flows involves the use of judgments, including estimation of the proved and risk-adjusted unproved oil and natural gas reserve quantities, timing of development and production, expected future commodity prices, capital expenditures and production costs and cash flows from integrated assets. The Company did not recognize impairment expense during the years ended December 31, 2018 and 2017. The Company recognized impairment expense of approximately $1.5 billion during the year ended December 31, 2016 related to its proved oil and natural gas properties. See Note 8 for additional information regarding the Company's impairment expense.

Unproved oil and natural gas properties are periodically assessed for impairment by considering future drilling and exploration plans, results of exploration activities, commodity price outlooks, planned future sales and expiration of all or a portion of the projects. During the years ended December 31, 2018, 2017 and 2016, the Company recognized expense of approximately $35 million, $27 million and $50 million, respectively, related to abandoned and expiring acreage, which is included in exploration and abandonments expense in the accompanying consolidated statements of operations.

Other property and equipment. Other capital assets include buildings, transportation equipment, computer equipment and software, telecommunications equipment, leasehold improvements and furniture and fixtures. These items are recorded at cost, or fair value if acquired, and are depreciated using the straight-line method based on expected lives of the individual assets or group of assets ranging from two to 39 years. The Company had other capital assets of $308 million and $234 million, net of accumulated depreciation of $109 million and $90 million, at December 31, 2018 and December 31, 2017, respectively. During the years ended December 31, 2018, 2017 and 2016, the Company recognized depreciation expense of $22 million, $21 million and $21 million, respectively.

Goodwill. As a result of the RSP Acquisition, as defined in Note 4, the Company has goodwill in the amount of $2.2 billion at December 31, 2018. Goodwill is not amortized but assessed for impairment on an annual basis, or more frequently if indicators of impairment exist. Impairment tests, which involve the use of estimates related to the fair market value of the

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

business operations with which goodwill is associated, are performed as of July 1 of each year. The balance of goodwill is allocated in its entirety to the Company's one reporting unit. When testing goodwill for impairment, the Company first performs a qualitative analysis to determine if it is more likely than not that the fair value of its reporting unit is less than its carrying value. If the analysis shows that the fair value is more likely than not less than the carrying value, then the Company performs a quantitative impairment test. The Company early adopted Accounting Standards Update ("ASU") No. 2017-04, "Intangibles – Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment" ("ASU 2017-04"). Per ASU 2017-04, if the results of the quantitative test are such that the fair value of the reporting unit is less than the carrying value, goodwill is reduced by an amount that is equal to the amount by which the carrying value of the reporting unit exceeds the fair value. Because of the recent decline in the price of oil and the volatility of the Company's common stock, the Company performed an analysis at December 31, 2018 and determined that it was not more likely than not that the fair value of its reporting unit was less than its carrying value. As a result, the Company did not recognize impairment expense during the year ended December 31, 2018.

Equity method investments. The Company accounts for its equity method investments under the equity method of accounting and includes the investment balance in other assets on the consolidated balance sheets. Gains and losses incurred from the Company's equity investments are recorded in other income (expense) on the consolidated statements of operations.

At December 31, 2018, the Company owned 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 Delaware Basin. In February 2018, Oryx obtained a term loan of $800 million. The proceeds were used in part to fund a cash distribution to its equity holders, of which the Company received a distribution of approximately $157 million. Of this amount, approximately $54 million fully offset the Company's net investment in Oryx. The remaining distribution of approximately $103 million was recorded in other income (expense) on the Company's consolidated statement of operations since the lenders to the term loan do not have recourse against the Company, and the Company has no contractual obligation to repay the distribution.

The Company's net investment in Oryx was zero and approximately $49 million at December 31, 2018 and 2017, respectively. The Company recorded income of approximately $4 million and $7 million for the years ended December 31, 2018 and 2017, respectively. The Company will not record income or loss on the Oryx investment until such net income is greater than the distribution in excess of its investment.

On December 26, 2018, the Company contributed certain infrastructure assets to WaterBridge Operating LLC (“WaterBridge”), an entity that operates and manages various water infrastructure assets located in the Permian Basin, in exchange for, among other consideration, 100,000 Series A-1 Preferred Units (“Preferred Units”). The Preferred Units contain certain redemption rights, incentives and restrictions, as specified in the agreement. The Company accounts for the investment using the equity method. In conjunction with the transaction, the Company entered into a water management services agreement with WaterBridge. The Company had no amounts due to WaterBridge at December 31, 2018. The Company’s investment in WaterBridge is recorded in other assets in the Company’s consolidated balance sheets.

In February 2017, the Company closed on the divestiture of its 50 percent membership interest in a midstream joint venture, Alpha Crude Connector, LLC (“ACC”), that constructed a crude oil gathering and transportation system in the Delaware Basin. See Note 5 for additional information regarding the disposition of ACC.

Regulatory and environmental compliance. The Company is subject to extensive federal, state and local environmental laws and regulations. These laws, which are often changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Regulatory liabilities relate to acquisitions where additional equipment is necessary to have facilities compliant with local, state and federal obligations and are capitalized. Environmental expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures that are noncapital in nature are recorded when environmental assessment and/or remediation is probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. Environmental liabilities normally involve estimates that are subject to revisions until settlement occurs. See Note 11 for additional information.

Litigation contingencies. The Company is a party to proceedings and claims incidental to its business. In each reporting period, the Company assesses these claims in an effort to determine the degree of probability and range of possible loss for potential accrual in its consolidated financial statements. The amount of any resulting losses may differ from these estimates. An accrual is recorded for a material loss contingency when its occurrence is probable and damages are reasonably estimable. See Note 11 for additional information.

Income taxes. The Company recognizes deferred tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

The Company evaluates uncertain tax positions for recognition and measurement in the consolidated financial statements. To recognize a tax position, the Company determines whether it is more likely than not that the tax position will be sustained upon examination, including resolution of any related appeals or litigation, based on the technical merits of the position. A tax position that meets the more likely than not threshold is measured to determine the amount of benefit to be recognized in the consolidated financial statements. The amount of tax benefit recognized with respect to any tax position is measured as the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement. At December 31, 2018, the Company had unrecognized tax benefits of approximately $63 million, primarily related to research and development credits. If all or a portion of the unrecognized tax benefit is sustained upon examination by the taxing authorities, the tax benefit will be recognized as a reduction to the Company’s deferred tax liability and will affect the Company’s effective tax rate in the period recognized. The timing as to when the Company will substantially resolve the uncertainties associated with the unrecognized tax benefit is uncertain. The Company has not recognized any interest or penalties relating to unrecognized tax benefits in its consolidated financial statements. Any interest or penalties would be recognized as a component of income tax expense.

On December 22, 2017, the President of the United States (the “President”) signed into law the tax bill commonly referred to as the “Tax Cuts and Job Act” (“TCJA”), significantly changing federal income tax laws. According to the Accounting Standards Codification (“ASC”) section 740, “Income Taxes,” (“ASC 740”), a company is required to record the effects of an enacted tax law or rate change in the period of enactment, which is the date the bill is signed by the President and becomes law. As a result of the enactment of the TCJA, the U.S. Securities and Exchange Commission (“SEC”) issued Staff Accounting Bulletin (“SAB”) No. 118, “Income Tax Accounting Implications of the Tax Cuts and Jobs Act,” (“SAB 118”) to provide guidance for companies that have not completed the accounting for the income tax effects of the TCJA in the period of enactment. SAB 118 allowed companies to report provisional amounts when based on reasonable estimates and to adjust these amounts during a measurement period of up to one year. The Company elected to apply SAB 118 and, as such, recorded provisional amounts for the income tax balances reported in its consolidated financial statements at December 31, 2017. At December 31, 2018, the Company completed its accounting for all tax effects of the TCJA and made an adjustment to its provisional amounts related to the deductibility of certain compensation based on available regulatory and interpretive guidance. See Note 12 for additional information regarding the Company’s deferred tax balances and the impacts of the TCJA.

Derivative instruments. The Company recognizes its derivative instruments, other than commodity derivative contracts that are designated as normal purchase and normal sale contracts, as either assets or liabilities measured at fair value. The Company nets the fair value of the derivative instruments by counterparty in the accompanying consolidated balance sheets when the right of offset exists. The Company does not have any derivatives designated as fair value or cash flow hedges. The Company may also enter into physical delivery contracts to effectively provide commodity price hedges. Because these contracts are not expected to be net cash settled, they are considered to be normal sales contracts and not derivatives. Therefore, these contracts are not recorded in the Company’s consolidated balance sheets.

Asset retirement obligations. The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related oil and natural gas property asset. Subsequently, the asset retirement cost included in the carrying amount of the related asset is allocated to expense through depletion of the asset. Changes in the liability due to passage of time are recognized as an increase in the carrying amount of the liability through accretion expense. Based on certain factors, including commodity prices and costs, the Company may revise its previous estimates of the liability, which would also increase or decrease the related oil and natural gas property asset.

Treasury stock. Treasury stock purchases are recorded at cost.

Revenue recognition. On January 1, 2018, the Company adopted ASC Topic 606, “Revenue from Contracts with Customers,” (“ASC 606”) using the modified retrospective approach, which only applies to contracts that were not completed as of the date of initial application. The adoption did not require an adjustment to opening retained earnings for the cumulative effect adjustment and does not have a material impact on the Company’s reported net income (loss), cash flows from operations or statement of stockholders’ equity.

The Company recognizes revenues from the sales of oil and natural gas to its customers and presents them disaggregated on the Company’s consolidated statements of operations. All revenues are recognized in the geographical region of the Permian Basin. Prior to the adoption of ASC 606, the Company recorded oil and natural gas revenues at the time of physical transfer of such products to the purchaser, which for the Company is primarily at the wellhead. The Company followed 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.

The Company enters into contracts with customers to sell its oil and natural gas production. Revenue on these contracts is recognized in accordance with the five-step revenue recognition model prescribed in ASC 606. Specifically, revenue is recognized when the Company's performance obligations under these contracts are satisfied, which generally occurs with the transfer of control of the oil and natural gas to the purchaser. Control is generally considered transferred when the following criteria are met: (i) transfer of physical custody, (ii) transfer of title, (iii) transfer of risk of loss and (iv) relinquishment of any repurchase rights or other similar rights. Given the nature of the products sold, revenue is recognized at a point in time based on the amount of consideration the Company expects to receive in accordance with the price specified in the contract. Consideration under the oil and natural gas marketing contracts is typically received from the purchaser one to two months after production. At December 31, 2018, the Company had receivables related to contracts with customers of approximately $466 million.

The following table shows the impact of the adoption of ASC 606 on the Company's current period results as compared to the previous revenue recognition standard, ASC Topic 605, "Revenue recognition" ("ASC 605"):

	Year Ended December 31, 2018		
(in millions)	**Under ASC 606**	**Under ASC 605**	**Increase (Decrease)**
Operating revenues:			
Oil sales	$ 3,443	$ 3,432	$ 11
Natural gas sales	708	674	34
Operating costs and expenses:			
Oil and natural gas production	590	600	(10)
Gathering, processing and transportation	55	-	55
Net income	$ 2,286	$ 2,286	$ -

Oil Contracts. The majority of the Company's oil marketing contracts transfer physical custody and title at or near the wellhead, which is generally when control of the oil has been transferred to the purchaser. The majority of the oil produced is sold under contracts using market-based pricing which is then adjusted for differentials based upon delivery location and oil quality. To the extent the differentials are incurred after the transfer of control of the oil, the differentials are included in oil sales on the statements of operations as they represent part of the transaction price of the contract. If the differentials, or other related costs, are incurred prior to the transfer of control of the oil, those costs are included in gathering, processing and transportation on the Company's consolidated statements of operations as they represent payment for services performed outside of the contract with the customer.

Natural Gas Contracts. The majority of the Company's natural gas is sold at the lease location, which is generally when control of the natural gas has been transferred to the purchaser. The natural gas is sold under (i) percentage of proceeds processing contracts, (ii) fee-based contracts or (iii) a hybrid of percentage of proceeds and fee-based contracts. Under the majority of the Company's contracts, the purchaser gathers the natural gas in the field where it is produced and transports it via pipeline to natural gas processing plants where natural gas liquid products are extracted. The natural gas liquid products and remaining residue gas are then sold by the purchaser. Under the percentage of proceeds and hybrid percentage of proceeds and fee-based contracts, the Company receives a percentage of the value for the extracted liquids and the residue gas. Under the fee-based contracts, the Company receives natural gas liquids and residue gas value, less the fee component, or is invoiced the fee component. To the extent control of the natural gas transfers upstream of the transportation and processing activities, revenue is recognized as the net amount received from the purchaser. To the extent that control transfers downstream of those costs, revenue is recognized on a gross basis, and the related costs are classified in gathering, processing and transportation on the Company's consolidated statements of operations.

The Company does not disclose the value of unsatisfied performance obligations under its contracts with customers as it applies the practical exemption in accordance with ASC 606. The exemption, as described in ASC 606-10-50-14(a), applies to variable consideration that is recognized as control of the product is transferred to the customer. Since each unit of product

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

represents a separate performance obligation, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

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. Such fees totaled approximately $19 million, $16 million and $17 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Stock-based compensation. Stock-based compensation expense is recognized in the Company’s financial statements on an accelerated basis over the awards’ vesting periods based on their grant date fair values. Stock-based compensation awards vest over a period generally ranging from one to five years. The Company utilizes the average of the high and low stock prices at each grant date to determine the fair value of restricted stock and the Monte Carlo simulation method to determine the fair value of performance unit awards. The Company recognizes forfeitures on stock-based compensation awards as they occur. When the Company adopted ASU No. 2016-09, “Compensation–Stock Compensation (Topic 718): Improvements to Employee Share-based Payment Accounting,” (“ASU 2016-09”) on January 1, 2017, it 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 tax liabilities by approximately $8 million.

Recently adopted accounting pronouncements. In January 2017, the Financial Accounting Standards Board (“FASB”) issued ASU No. 2017-04, which simplifies how an entity subsequently measures goodwill by eliminating Step 2 from the goodwill impairment test. In place of Step 2, an entity will recognize an impairment charge for the amount by which the carrying amount of a reporting unit exceeds its fair value; however, the loss recognized should not exceed the total amount of goodwill allocated to the reporting unit. The Company early adopted this standard beginning in the third quarter of 2018. The adoption of this standard did not have an impact on the Company’s financial results.

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. The Company adopted this standard on January 1, 2018. See Notes 4 and 5 for information regarding the Company's significant acquisitions and divestitures.

New accounting pronouncements issued but not yet adopted. In February 2016, the FASB issued ASU No. 2016-02, "Leases (Topic 842)" ("ASU 2016-02"), 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. The Company made policy elections to not capitalize short-term leases for all asset classes and to not separate non-lease components from lease components for all asset classes except for vehicles. The Company also plans to not elect the package of practical expedients that allows for certain considerations under the original "Leases (Topic 840)" accounting standard ("Topic 840") to be carried forward upon adoption of ASU 2016-02.

The Company enters into lease agreements to support its operations. These agreements are for leases on assets such as office space, vehicles, well equipment and drilling rigs. The Company has completed the process of reviewing and determining the contracts to which this new guidance applies. Upon adoption, on January 1, 2019, the Company recognized approximately $35 million of right-of-use assets, of which approximately $19 million and $16 million relate to the Company's operating and financing leases, respectively, and approximately $37 million of associated lease liabilities that are not currently recognized under applicable guidance.

In January 2018, the FASB issued ASU No. 2018-01, "Land Easement Practical Expedient for Transition to Topic 842," which provides an optional practical expedient to not evaluate land easements that existed or expired before the adoption of ASU 2016-02 and that were not previously accounted for as leases under Topic 840. The Company enters into land easements on a routine basis as part of its ongoing operations and has many such agreements currently in place; however, the Company does not currently account for any land easements under Topic 840. As this guidance serves as an amendment to ASU 2016-02, the Company will elect this practical expedient, which becomes effective upon the date of adoption of ASU 2016-02. After the adoption of ASU 2016-02, the Company will assess any new land easements to determine whether the arrangement should be accounted for as a lease. In July 2018, the FASB issued ASU No. 2018-11, "Targeted Improvements," which provides a transition election to not restate comparative periods for the effects of applying the new lease standard. This transition election permits entities to change the date of initial application to the beginning of the year of adoption and to

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

recognize the effects of applying the new standard as a cumulative-effect adjustment to the opening balance of retained earnings. The Company elected this transition approach, however the cumulative impact of adoption in the opening balance of retained earnings as of January 1, 2019 was zero.

In June 2016, the FASB issued ASU No. 2016-13, “Financial Instruments–Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments,” (“Topic 326”) 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. In November 2018, the FASB issued ASU No. 2018-19, “Codification Improvements to Topic 326, Financial Instruments-Credit Losses,” which makes amendments to clarify the scope of the guidance, including the amendment clarifying that receivables arising from operating leases are not within the scope of Topic 326. 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 July 2018, the FASB issued ASU No. 2018-09, “Codification Improvements,” (“ASU 2018-09”) which makes amendments to multiple codification topics to clarify, correct errors in, or make minor improvements to the accounting standards codification. The effective date of the standard is dependent on the facts and circumstances of each amendment. Some amendments do not require transition guidance and will be effective upon the issuance of this standard. Many of the amendments in ASU 2018-09 will be effective in annual periods beginning after December 15, 2018. The Company will be required to adopt this standard in the first quarter of fiscal 2019. The Company is currently assessing the effect that this ASU will have on the financial position, results of operations, and disclosures.

On August 17, 2018, the SEC issued a final rule that amends certain of its disclosure requirements that have become redundant, duplicative, overlapping, outdated or superseded, in light of other disclosure requirements, U.S. GAAP or changes in the information environment. The amendments are intended to facilitate the disclosure of information to investors and simplify compliance without significantly altering the total mix of information provided to investors. The final rule amends numerous SEC rules, items and forms covering a diverse group of topics, including, but not limited to, changes in stockholders’ equity. The final rule extends to interim periods the annual disclosure requirement in SEC Regulation S-X, Rule 3-04, of presenting changes in stockholders’ equity. The registrants will be required to analyze changes in stockholders’ equity in the form of a reconciliation for the current quarter and year-to-date interim periods and comparative periods in the prior year. The final rule became effective for all filings submitted on or after November 5, 2018.

In November 2018, the FASB issued ASU No. 2018-18, “Collaborative Arrangements (Topic 808): Clarifying the Interaction between Topic 808 and Topic 606,” (“ASU 2018-18”) which, among other things, clarifies that (i) certain transactions between collaborative arrangement participants should be accounted for as revenue under Topic 606 when the collaborative arrangement participant is a customer in the context of a unit of account, (ii) adds unit-of-account guidance in Topic 808 to align with the guidance in Topic 606 and (iii) requires that in a transaction with a collaborative arrangement participant that is not directly related to sales to third parties, presenting the transaction together with revenue recognized under Topic 606 is precluded if the collaborative arrangement participant is not a customer. ASU 2018-18 is effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years and early adoption is permitted. The amendments in this update should be applied retrospectively to the date of initial application of Topic 606. An entity should recognize the cumulative effect of initially applying the amendments as an adjustment to the opening balance of retained earnings of the later of the earliest annual period presented and the annual period that includes the date of the entity’s initial application of Topic 606. The Company is currently assessing the effect that ASU 2018-18 will have on its financial position, results of operations and disclosures.

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. The capitalized exploratory well costs are carried in unproved oil and natural gas properties. See Unaudited Supplementary Data 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 each of the years ended December 31, 2018, 2017 and 2016:

(in millions)	**Years Ended December 31, 2018**	**2017**	**2016**
Beginning capitalized exploratory well costs	$ 182	$ 151	$ 116
Additions to exploratory well costs pending the determination of proved reserves (a)	581	180	144
Reclassifications due to determination of proved reserves	(226)	(147)	(86)
Exploratory well costs charged to expense	-	-	(6)
Disposition of wells	(14)	(2)	(17)
Ending capitalized exploratory well costs	$ 523	$ 182	$ 151

(a) Includes $82 million of exploratory well costs acquired as part of the RSP Acquisition, as defined in Note 4.

The following table provides an aging at December 31, 2018 and 2017 of capitalized exploratory well costs based on the date drilling was completed:

(in millions, except number of projects)	**December 31, 2018**	**2017**
Capitalized exploratory well costs that have been capitalized for a period of one year or less	$ 523	$ 180
Capitalized exploratory well costs that have been capitalized for a period greater than one year	-	2
Total capitalized exploratory well costs	$ 523	$ 182
Number of projects with exploratory well costs that have been capitalized for a period greater than one year	-	2

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

Note 4. ***RSP Acquisition***

On July 19, 2018, the Company completed the acquisition of RSP Permian, Inc. (“RSP”) through an all-stock transaction (the “RSP Acquisition”). RSP was an independent oil and natural gas company engaged in the acquisition, exploration, development and production of unconventional oil and associated liquids-rich natural gas reserves in the Permian Basin of West Texas. The vast majority of RSP’s acreage was located on large, contiguous acreage blocks in the core of the Midland Basin and the Delaware Basin. The acquisition added approximately 92,000 net acres. Under the terms of the Agreement and Plan of Merger (the “Acquisition Agreement”), each share of RSP common stock was converted into 0.320 of a share of the Company’s common stock. The Company issued approximately 51 million shares of common stock at a price of $148.27 per share, resulting in total consideration paid by the Company to the former RSP shareholders of approximately $7.5 billion.

In connection with the closing of the RSP Acquisition, the Company repaid outstanding principal under RSP’s revolving credit facility and redeemed and canceled all of RSP’s outstanding unsecured senior notes. See Note 10 for additional information regarding the Company’s debt activity.

In connection with the RSP Acquisition, the Company incurred approximately $32 million of costs related to consulting, investment banking, advisory, legal and other acquisition-related fees during the year ended December 31, 2018, which are included in transaction costs in operating costs and expenses on the consolidated statements of operations. In addition, the Company acquired 670,369 shares of common stock from RSP employees for the payment of withholding taxes due on the vesting of their restricted shares pursuant to the Acquisition Agreement, resulting in an increase of approximately $32 million in the Company’s treasury stock balance.

Purchase price allocation. The RSP Acquisition has been accounted for as a business combination, using the acquisition method. The following table represents the preliminary allocation of the total purchase price of RSP to the identifiable assets acquired and the liabilities assumed based on the fair values at the acquisition date, with any excess of the purchase price over the estimated fair value of the identifiable net assets acquired recorded as goodwill. Any value assigned to goodwill is not expected to be deductible for income tax purposes. Certain data necessary to complete the purchase price allocation is not yet available, including tax return data from RSP’s short period ending July 19, 2018 that provides underlying tax basis in assets and liabilities and uncertain tax positions.

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

The following table sets forth the Company's preliminary purchase price allocation:

(in millions)		
Total purchase price	**$**	**7,549**
Fair value of liabilities assumed:		
Accounts payable – trade	$	48
Accrued drilling costs		74
Current derivative instruments		10
Other current liabilities		124
Long-term debt		1,758
Deferred income taxes		515
Asset retirement obligations		20
Noncurrent derivative instruments		5
Total liabilities assumed	**$**	**2,554**
Total purchase price plus liabilities assumed	**$**	**10,103**
Fair value of assets acquired:		
Accounts receivable	$	194
Current derivative instruments		36
Other current assets		22
Proved oil and natural gas properties		4,055
Unproved oil and natural gas properties		3,565
Other property and equipment		5
Noncurrent derivative instruments		2
Implied goodwill		2,224
Total assets acquired	**$**	**10,103**

The fair values of assets acquired and liabilities assumed were based on the following key inputs:

Oil and natural gas properties

The fair value of proved and unproved oil and natural gas properties was measured using valuation techniques that convert the future cash flows to a single discounted amount. Significant inputs to the valuation of proved and unproved oil and natural gas properties include estimates of: (i) recoverable reserves; (ii) production rates; (iii) future operating and development costs; (iv) future commodity prices; and (v) a market-based weighted average costs of capital. The Company utilized a combination of the NYMEX strip pricing and consensus pricing, adjusted for differentials, to value the reserves. The Company's estimates of commodity prices for purposes of determining discounted cash flows ranged from a 2018 price of $66.59 per barrel of oil decreasing to a 2022 price of $63.41 per barrel of oil. Similarly, natural gas prices ranged from a 2018 price of $2.80 per MMBtu then rising to a 2022 price of $3.09 per MMBtu. Both oil and natural gas commodity prices were held flat after 2022 and adjusted for inflation. The Company then applied various discount rates depending on the classification of reserves and other risk characteristics. Management utilized the assistance of a third-party valuation expert to estimate the value of the oil and natural gas properties acquired.

The fair value of asset retirement obligations totaled $20 million and is included in proved oil and natural gas properties with a corresponding liability in the table above. The fair value was determined based on a discounted cash flow model, which included assumptions of the estimated current abandonment costs, discount rate, inflation rate and timing associated with the incurrence of these costs.

The inputs used to value oil and natural gas properties and asset retirement obligations require significant judgment and estimates made by management and represent Level 3 inputs.

Financial instruments and other

The fair value measurements of long-term debt were estimated based on the market prices and represent Level 1 inputs. The fair value measurements of derivative instruments assumed were determined based on published forward commodity price curves, implied market volatility, contract terms and prices and discount factors as of the close date of the RSP Acquisition and represent Level 2 inputs. The fair values of commodity derivative instruments in an asset position include a measure of counterparty nonperformance risk and the derivative instruments in a liability position include a measure of the Company's own nonperformance risk, each based on the current published credit default swap rates.

The fair values determined for accounts receivable, accounts payable – trade, accrued drilling costs and other current liabilities were equivalent to the carrying value due to their short-term nature.

Other current liabilities include approximately $16 million of liabilities primarily related to certain regulatory obligations.

Deferred income taxes

The RSP Acquisition qualified as a tax-free merger whereby the Company acquired carryover tax basis in RSP's assets and liabilities, adjusted for differences between the purchase price allocated to the assets acquired and liabilities assumed based on the fair value and the carryover tax basis. See Note 12 for additional discussion of deferred income taxes.

Goodwill recognized is primarily attributable to the following factors: (i) operating and administrative synergies and (ii) net deferred tax liabilities arising from the differences between the purchase price allocated to RSP's assets and liabilities based on fair value and the tax basis of these assets and liabilities. For the operating and administrative synergies, the total consideration for the RSP Acquisition included a control premium, which resulted in a higher value compared to the fair value of net assets acquired. There are also other qualitative assumptions of long-term factors that the RSP Acquisition creates for the

Company’s stockholders, including additional potential for exploration and development opportunities and additional scale and efficiencies in basins in which the Company operates.

Approximately $506 million of operating revenues and approximately $274 million of income from operations attributed to the RSP Acquisition are included in the Company’s results of operations from the closing date on July 19, 2018 through December 31, 2018.

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

Pro forma data. The following unaudited pro forma combined condensed financial data for the years ended December 31, 2018 and 2017 was derived from the historical financial statements of the Company giving effect to the RSP Acquisition, as if it had occurred on January 1, 2017. The below information reflects pro forma adjustments for the issuance of the Company's common stock in exchange for RSP's outstanding shares of common stock, as well as pro forma adjustments based on available information and certain assumptions that the Company believes are reasonable, including (i) the Company's common stock issued to convert RSP's outstanding shares of common stock and equity awards as of the closing date of the RSP Acquisition, (ii) the depletion of RSP's fair-valued proved oil and gas properties and (iii) the estimated tax impacts of the pro forma adjustments.

Additionally, pro forma earnings were adjusted to exclude acquisition-related costs incurred by the Company of approximately $32 million for the year ended December 31, 2018 and acquisition-related costs incurred by RSP and severance payments to certain RSP employees that totaled approximately $56 million for the year ended December 31, 2018. The pro forma results of operations do not include any cost savings or other synergies that may result from the RSP Acquisition. The pro forma financial data does not include the pro forma results of operations for any other acquisitions made during the period. The pro forma combined condensed financial data has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the RSP Acquisition taken place on January 1, 2017 and is not intended to be a projection of future results.

(in millions, except per share amounts)	**Years Ended December 31, 2018**	**2017**
	(unaudited)	
Operating revenues	$ 4,798	$ 3,390
Net income	$ 2,552	$ 1,197
Earnings per share:		
Basic net income	$ 12.75	$ 6.02
Diluted net income	$ 12.73	$ 5.99

Note 5. ***Acquisitions, divestitures and nonmonetary transactions***

During the year ended December 31, 2018, the Company closed on the following transactions (exclusive of the RSP Acquisition disclosed in Note 4):

February 2018 acquisition and divestiture. In February 2018, the Company closed on an acquisition treated as a business combination where it received producing wells with approximately 5 MBoepd along with approximately 21,000 net acres, primarily located in the Midland Basin. As consideration for the non-cash acquisition, the Company divested approximately 34,000 net acres, primarily comprised of approximately 32,000 net acres in the northern Delaware Basin, with production of 3 MBoepd. The business acquired was valued at approximately $755 million as compared to the historical book value of the divested assets of approximately $180 million, which resulted in a non-cash gain of approximately $575 million. The fair value of the assets acquired totaled approximately $755 million, which was comprised of approximately $245 million of proved properties, approximately $480 million of unproved properties and approximately $30 million of other assets. The fair value of the assets received in the business combination approximated the fair value of assets disposed.

Delaware Basin divestitures. In January 2018, the Company closed on two asset sales transactions of certain non-core assets in Reeves and Ward Counties, Texas, with combined proceeds of approximately $280 million. After direct transaction costs, the Company recorded a pre-tax gain of approximately $134 million, which is included in gain on disposition of assets, net on its consolidated statement of operations for the year ended December 31, 2018. The assets divested included proved and unproved oil and natural gas properties on approximately 20,000 net acres.

These divestitures completed 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, that the Company entered into concurrent with its July 2017 Midland Basin acquisition, as further described below.

Upon completion of the Reverse 1031 Exchange in January 2018, the assets and liabilities attributable to the acquisition that were held by the VIE were conveyed to the Company, and the VIE structure was dissolved.

Nonmonetary transactions. During 2018, the Company completed multiple nonmonetary transactions. These transactions included exchanges of both proved and unproved oil and natural gas properties. Certain of these transactions were accounted for at fair value and, as a result, the Company recorded pre-tax gains of approximately $15 million.

During the year ended December 31, 2017, the Company closed on the following transactions:

Delaware Basin acquisition. In January and April 2017, the Company closed on the two-part 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 which is included in gain on disposition of assets, net on its consolidated statement of operations for the year ended December 31, 2017. The Company's net investment in ACC at the time of closing was approximately $129 million.

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.

Concurrent with the acquisition, the Company entered into a transaction structured as a Reverse 1031 Exchange. 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 December 31, 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 held by the VIE attributable to the acquisition were conveyed to the Company and the VIE structure terminated upon the completion of the Reverse 1031 Exchange. At December 31, 2017, the VIE's total assets and liabilities included in the Company's consolidated balance sheet were approximately $608 million and $604 million, respectively.

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

Nonmonetary transactions. During 2017, the Company completed multiple nonmonetary transactions. The transactions included exchanges of both proved and unproved oil and natural gas properties. Certain of these transactions were accounted for at fair value and as a result the Company recorded pre-tax gains totaling approximately $26 million.

During the year ended December 31, 2016, the Company closed on the following transactions:

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

Delaware Basin acquisition. In March 2016, the Company completed an acquisition of 80 percent of a third-party seller's interest in certain oil and natural gas properties and related assets in the southern Delaware Basin. As consideration for the acquisition, the Company issued to the seller approximately 2.2 million shares of common stock with an approximate value of $231 million, $146 million in cash and $40 million to carry a portion of the seller's future development costs in these properties that was expended in 2016 and 2017 and included in costs incurred.

Reliance acquisition. In October 2016, the Company completed an acquisition of approximately 40,000 net acres in the Midland Basin and other assets from Reliance Energy, Inc. (collectively, the "Reliance Acquisition") for approximately $1.7 billion. As consideration for the acquisition, the Company paid approximately $1.2 billion in cash and issued to the seller approximately 3.9 million shares of common stock with an approximate value of $0.5 billion.

Approximately $29 million of operating revenues and approximately $10 million of income from operations attributed to the Reliance Acquisition are included in the Company's results of operations from the closing date in October 2016 through the year ended December 31, 2016.

Pro forma data. The following unaudited pro forma combined condensed financial data for the year ended December 31, 2016 was derived from the historical financial statements of the Company giving effect to the Reliance Acquisition, as if it had occurred on January 1, 2016. The results of operations for the Reliance Acquisition are included in the Company's results of operations since the closing date in October 2016 through December 31, 2018. The pro forma financial data does not include the pro forma results of operations for any other acquisitions made during the period. The pro forma combined condensed financial data has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the Reliance Acquisition taken place on January 1, 2016 and is not intended to be a projection of future results.

(in millions, except per share amounts)	**Year Ended December 31, 2016** (unaudited)	
Operating revenues	$	1,717
Net loss	$	(1,396)
Earnings per common share:		
Basic net loss	$	(10.36)
Diluted net loss	$	(10.36)

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

Note 6. *Asset retirement obligations*

The Company's asset retirement obligations represent the estimated present value of the estimated cash flows the Company will incur to plug, abandon and remediate its producing properties at the end of their productive lives, in accordance with applicable state laws. Market risk premiums associated with asset retirement obligations are estimated to represent a component of the Company's credit-adjusted risk-free rate that is utilized in the calculations of asset retirement obligations.

The Company's asset retirement obligation transactions during the years ended December 31, 2018, 2017 and 2016 are summarized in the table below:

(in millions)	**Years Ended December 31, 2018**	**2017**	**2016**
Asset retirement obligations, beginning of period	$ 141	$ 130	$ 120
Liabilities incurred from new wells	4	2	2
Liabilities assumed in acquisitions	26	10	13
Accretion expense	10	8	7
Disposition of wells	(4)	(1)	(11)
Liabilities settled upon plugging and abandoning wells	(7)	(5)	(1)
Revision of estimates (a)	9	(3)	-
Asset retirement obligations, end of period	$ 179	$ 141	$ 130

(a) The revision to the Company s asset retirement obligation estimates for the year ended December 31, 2018 is primarily due to an increase in pad reclamation costs in New Mexico.

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

Note 7. *Incentive plans*

Defined contribution plan. The Company sponsors a 401(k) defined contribution plan for the benefit of its employees. During the years ended December 31, 2018, 2017 and 2016, the Company matched 100 percent of employee contributions, not to exceed 10 percent of the employee's annual eligible compensation, subject to federal limits. The Company's contributions to the plan for the years ended December 31, 2018, 2017 and 2016 were approximately $12 million, $10 million and $9 million, respectively.

Stock incentive plan. The Company's 2015 Stock Incentive Plan (the "Plan") provides for granting stock options, restricted stock awards and performance awards to directors, officers and employees of the Company. A total of 10.5 million shares of common stock have been authorized for issuance under the Plan. At December 31, 2018, the Company had 1.4 million shares of common stock available for future grants. Shares issued as a result of awards granted under the Plan are generally new common shares.

Restricted stock awards. All restricted shares are legally issued and outstanding. If an employee terminates employment prior to the restriction lapse date, the awarded shares are forfeited and cancelled and are no longer considered issued and outstanding. A summary of the Company's restricted stock award activity for the year ended December 31, 2018 is presented below:

	Number of Restricted Shares	Weighted Average Grant Date Fair Value Per Share	
Outstanding at December 31, 2017	1,149,246	$	118.02
Shares granted	686,996(a)	$	137.31
Shares cancelled / forfeited	(85,228)	$	125.86
Lapse of restrictions	(386,315)	$	115.06
Outstanding at December 31, 2018	1,364,699	$	128.08

(a)

Includes 167,122 restricted shares granted to RSP employees on July 20, 2018 that became employees of the Company.

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

For restricted stock awards granted, stock-based compensation expense is recognized in the Company's consolidated financial statements on an accelerated basis over the awards' vesting periods based on their grant date fair values. The restricted stock-based compensation awards generally vest over a period ranging from one to five years. The Company utilizes the average of the high and low stock prices on the grant date for the fair value of restricted stock.

The following table summarizes information about stock-based compensation for the Company's restricted stock awards activity under the Plan for years ended December 31, 2018, 2017 and 2016:

	Years Ended December 31,		
(in millions)	**2018**	**2017**	**2016**
Fair value for awards granted during the period (a)	$ 94	$ 60	$ 51
Fair value for awards vested during the period	$ 54	$ 49	$ 45
Stock-based compensation expense from restricted stock	$ 60	$ 43	$ 41
Income tax benefit related to restricted stock	$ 14	$ 11	$ 15

(a) The weighted average grant date fair value per share amounts were $137.31, $123.16 and $112.78 for the years ended December 31, 2018, 2017 and 2016, respectively.

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

Performance unit awards. During the years ended December 31, 2018, 2017 and 2016, the Company awarded performance units to its officers under the Plan. The number of shares of common stock that will ultimately be issued 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 grant date fair value was determined using the Monte Carlo simulation method and is being expensed ratably over the performance period. Expected volatilities utilized in the model were estimated using a historical period consistent with the remaining performance period of approximately three years. The risk-free interest rate was based on the U.S. Treasury rate for a term commensurate with the expected life of the grant.

The Company used the following assumptions to estimate the fair value of performance unit awards granted during the years ended December 31, 2018, 2017 and 2016:

	Years Ended December 31,		
	2018	**2017**	**2016**
Risk-free interest rate	2.00%	1.47%	1.31%
Range of volatilities	23.5% - 64.0%	24.8% - 60.2%	31.6% - 59.0%

The following table summarizes the performance unit activity for the year ended December 31, 2018:

	Number of Units	**Grant Date Fair Value**
Performance units:		
Outstanding at December 31, 2017	247,647	$ 146.10
Units granted (a)	111,490	$ 216.03
Lapse of restrictions (b)	(140,746)	$ 114.81
Outstanding at December 31, 2018	218,391	$ 201.97

(a) Reflects the amount of performance units granted. The actual payout of shares will be between zero and 300 percent of the performance units granted depending on the Company's performance at the end of the performance period.

(b) On December 31, 2018, the performance period ended for these performance units. Each unit converted into 1.75 shares representing 246,314 shares of common stock issued on January 2, 2019.

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

The following table summarizes information about stock-based compensation expense for performance units for the years ended December 31, 2018, 2017 and 2016:

(in millions)	**Years Ended December 31, 2018**	**2017**	**2016**
Fair value for awards granted during the period (a)	$ 24	$ 20	$ 19
Fair value for awards vested during the period	$ 68	$ 68	$ 33
Stock-based compensation expense from performance units	$ 22	$ 17	$ 18
Income tax benefit related to performance units	$ 14	$ 2	$ 7

(a) The weighted average grant date fair value per unit amounts were $216.03, $183.48 and $114.81 for the years ended December 31, 2018, 2017 and 2016, respectively.

On January 1, 2017, the Company adopted ASU 2016-09 and elected to account for forfeitures of share-based payments as they occur. During the years ended December 31, 2018 and 2017, the Company recorded actual forfeitures of $4 million and $8 million respectively, which reduced total stock-based compensation expense. During the year ended December 31, 2016, the Company recorded $5 million of estimated forfeitures.

Future stock-based compensation expense. The following table reflects the future stock-based compensation expense to be recorded for all the stock-based compensation awards that were outstanding at December 31, 2018:

(in millions)

2019	$	65
2020		34
2021		10
Thereafter		1
Total	$	110

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

Note 8. ***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) current market and contractual prices for the underlying instruments and (iv) volatility factors, as well as other relevant economic measures.

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

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 December 31, 2018 and 2017:

(in millions)	December 31, 2018 Carrying Value	December 31, 2018 Fair Value	December 31, 2017 Carrying Value	December 31, 2017 Fair Value
Assets:				
Derivative instruments	$ 695	$ 695	$ -	$ -
Liabilities:				
Derivative instruments	$ -	$ -	$ 379	$ 379
Credit facility	$ 242	$ 242	$ 322	$ 322
$600 million 4.375% senior notes due 2025 (a)	$ 594	$ 591	$ 593	$ 624
$1,000 million 3.75% senior notes due 2027 (a)	$ 989	$ 939	$ 987	$ 1,012
$1,000 million 4.3% senior notes due 2028 (a)	$ 988	$ 980	$ -	$ -
$800 million 4.875% senior notes due 2047 (a)	$ 789	$ 761	$ 789	$ 874
$600 million 4.85% senior notes due 2048 (a)	$ 592	$ 573	$ -	$ -

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

Credit facility. The carrying amount of the Company's amended and restated credit facility ("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.

103

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

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 atDecember 31, 2018 and 2017. The Company nets the fair value of derivative instruments by counterparty in the Company's consolidated balance sheets.

	December 31, 2018					
	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	$ -	$ 543	$ -	$ 543	$ (59)	$ 484
Noncurrent:						
Commodity derivatives	-	243	-	243	(32)	211
Liabilities						
Current:						
Commodity derivatives	-	(59)	-	(59)	59	-
Noncurrent:						
Commodity derivatives	-	(32)	-	(32)	32	-

Net derivative instruments	$	-	$	695	$	-	$	695	$	-	$	695

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

	December 31, 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	$ -	$ 13	$ -	$ 13	$ (13)	$ -
Noncurrent:						
Commodity derivatives	-	1	-	1	(1)	-
Liabilities						
Current:						
Commodity derivatives	-	(290)	-	(290)	13	(277)
Noncurrent:						
Commodity derivatives	-	(103)	-	(103)	1	(102)
Net derivative instruments	$ -	$ (379)	$ -	$ (379)	$ -	$ (379)

Concentrations of credit risk. At December 31, 2018, 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. See Note 13 for information regarding the Company’s major customers and derivative counterparties.

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 9 for additional information regarding the Company's derivative activities.

105

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

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 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 December 31, 2018, 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 2019 price of $47.09 per barrel of oil increasing to a 2025 price of $53.10 per barrel of oil. Natural gas prices ranged from a 2019 price of $2.78 per Mcf of natural gas decreasing to a 2021 price of $2.61 per Mcf then rising to a 2025 price of $2.90 per Mcf of natural gas. Both oil and natural gas commodity prices for this purpose were held flat after 2025. The Company did not recognize any impairment loss during the years ended December 31, 2018 or 2017.

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) discount rate. The expected future net cash flows are 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.

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) 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.

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

Note 9. *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's derivative financial instruments have historically consisted of oil and natural gas swaps and oil basis swaps. Swap contracts allow the Company to receive a fixed price and pay a floating market price to the counterparty for the hedged commodity. Basis swap contracts allow the Company to receive a fixed price differential between market indices for the price of oil.

In connection with the RSP Acquisition, the Company assumed certain oil collar and three-way collar contracts. In these contracts, each collar has an established floor price and ceiling price, and certain collars also include a short put price (three-way collars). When the settlement price is below the established floor price, the Company receives an amount from its counterparty equal to the difference between the settlement price and the floor price multiplied by the hedged contract volume. When the settlement price is above the established ceiling price, the Company pays its counterparty an amount equal to the difference between the settlement price and the ceiling price multiplied by the hedged contract volume. When the settlement price is between the established floor and the ceiling, no amounts are due to or from the counterparty. In case of a three-way collar, when the settlement price is below the short put price, the Company receives from its counterparty an amount equal to the difference of the floor price and the short put price multiplied by the hedged contract volume.

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 records these contracts 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 years ended December 31, 2018, 2017 and 2016:

	Years Ended December 31,		
(in millions)	**2018**	**2017**	**2016**
Gain (loss) on derivatives:			
Oil derivatives	$ 848	$ (172)	$ (337)
Natural gas derivatives	(16)	46	(32)
Total	$ 832	$ (126)	$ (369)

The following table represents the Company's net cash receipts from (payments on) derivatives for the years ended December 31, 2018, 2017 and 2016:

	Years Ended December 31,		
(in millions)	**2018**	**2017**	**2016**
Net cash receipts from (payments on) derivatives:			
Oil derivatives	$ (213)	$ 79	$ 609
Natural gas derivatives	(5)	-	16
Total	$ (218)	$ 79	$ 625

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

Commodity derivative contracts at December 31, 2018. The following table sets forth the Company's outstanding derivative contracts at December 31, 2018. When aggregating multiple contracts, the weighted average contract price is disclosed. All of the Company's derivative contracts at December 31, 2018 are expected to settle by December 31, 2021.

		First Quarter		Second Quarter		Third Quarter		Fourth Quarter	Total
Oil Price Swaps: (a)									
2019:									
Volume (Bbl)		12,352,250		11,199,750		10,434,000		9,852,000	43,838,000
Price per Bbl	$	56.75	$	56.36	$	56.20	$	56.08	$ 56.37
2020:									
Volume (Bbl)		7,408,500		7,072,500		6,693,000		6,458,000	27,632,000
Price per Bbl	$	58.38	$	58.37	$	58.24	$	58.22	$ 58.31
Oil Costless Collars: (a)									
2019:									
Volume (Bbl)		1,335,250		1,213,250		1,135,000		1,058,000	4,741,500
Ceiling price per Bbl	$	64.67	$	64.00	$	63.47	$	62.95	$ 63.83
Floor price per Bbl	$	56.46	$	56.06	$	55.74	$	55.43	$ 55.96
Oil Basis Swaps: (b)									
2019:									
Volume (Bbl)		11,693,000		11,601,500		11,178,000		10,717,000	45,189,500
Price per Bbl	$	(3.00)	$	(3.04)	$	(2.99)	$	(3.10)	$ (3.03)
2020:									
Volume (Bbl)		8,645,000		8,645,000		8,740,000		8,740,000	34,770,000
Price per Bbl	$	(0.82)	$	(0.82)	$	(0.82)	$	(0.82)	$ (0.82)
2021:									
Volume (Bbl)		1,350,000		1,365,000		1,380,000		1,380,000	5,475,000
Price per Bbl	$	0.59	$	0.59	$	0.59	$	0.59	$ 0.59
Natural Gas Price Swaps: (c)									
2019:									
Volume (MMBtu)		10,891,533		17,241,387		17,298,537		17,209,535	62,640,992
Price per MMBtu	$	2.86	$	2.87	$	2.87	$	2.87	$ 2.87
2020:									

Volume (MMBtu)		4,413,500	4,413,500	4,278,000	4,278,000	17,383,000
Price per MMBtu	$	2.70$	2.70$	2.70$	2.70$	2.70

(a) The oil derivative contracts are settled based on the NYMEX – WTI monthly average futures price.
(b) The basis differential price is between Midland – WTI and Cushing – WTI. The majority of these contracts are settled on a calendar-
month basis, while certain contracts assumed in connection with the RSP Acquisition are settled on a trading-month basis.
(c) The natural gas derivative contracts are settled 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," as defined in Note 10, under the Credit Facility, 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 10 for additional information regarding the Credit Facility.

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

Note 10. ***Debt***

The Company's debt consisted of the following at December 31, 2018 and 2017:

(in millions)	**December 31, 2018**	**December 31, 2017**
Credit facility due 2022	$ 242	$ 322
4.375% unsecured senior notes due 2025 (a)	600	600
3.75% unsecured senior notes due 2027	1,000	1,000
4.3% unsecured senior notes due 2028	1,000	-
4.875% unsecured senior notes due 2047	800	800
4.85% unsecured senior notes due 2048	600	-
Unamortized original issue discount	(10)	(6)
Senior notes issuance costs, net	(38)	(25)
Less: current portion	-	-
Total long-term debt	$ 4,194	$ 2,691

(a) For each of the twelve month periods beginning on January 15, 2020, 2021, 2022, 2023 and thereafter, these notes are callable at 103.281%, 102.188%, 101.094% and 100%, respectively.

Credit Facility. The Credit Facility has a maturity date of May 9, 2022. At December 31, 2018, 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 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 in 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 December 31, 2018, 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 (5.5 percent at December 31, 2018), (b) the federal funds effective rate plus 0.5 percent and (c) 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. During the years ended December 31, 2018, 2017 and 2016, the Company incurred commitment fees on the unused portion of the available commitments of $5 million, $6 million and $8 million, respectively. The Company had $1.8 billion of unused commitments, net of letters of credit, under the Credit Facility at December 31, 2018.

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, as defined, before interest expense, income taxes, depletion, depreciation, and amortization, exploration expense and other non-cash income and expenses to be no greater than 4.25 to 1.0,

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

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 17, and rank equally in right of payments with one another.

On July 2, 2018, the Company issued $1,600 million in aggregate principal amount of unsecured senior notes, consisting of $1,000 million in aggregate principal amount of 4.3% unsecured senior notes due 2028 (the “4.3% Notes”) and $600 million in aggregate principal amount of 4.85% unsecured senior notes due 2048 (the “4.85% Notes” and, together with the 4.3% Notes, the “Notes”). The 4.3% Notes were issued at a price equal to 99.660 percent of par, and the 4.85% Notes were issued at a price equal to 99.740 percent of par. The net proceeds of approximately $1,579 million were used to redeem and cancel all of RSP’s outstanding $700 million aggregate principal amount of 6.625% unsecured senior notes due 2022 (the “RSP 2022 Notes”) and $450 million aggregate principal amount of 5.25% unsecured senior notes due 2025 (the “RSP 2025 Notes” and, together with the RSP 2022 Notes, the “RSP Notes”). The Company made aggregate payments of approximately $1.2 billion to redeem and cancel the RSP Notes, including make-whole call premiums of approximately $35 million and $33 million for the RSP 2022 Notes and RSP 2025 Notes, respectively. The Company also paid accrued interest of approximately $14 million on the RSP Notes. The remaining proceeds, along with borrowings under the Credit Facility, were used to repay the $540 million of outstanding principal under RSP’s revolving credit facility, including $1 million in accrued interest. See Note 4 for additional information regarding the RSP Acquisition.

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 “2017 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 2017 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.

As a result of these transactions, the Company recorded a loss on extinguishment of debt for the year ended December 31, 2017 as follows:

(in millions)	Senior Notes September 2017 Tender Offer	Extinguishment	Total
Cash:			
Tender premium	$ 36	$ -	$ 36
Make-whole premium	-	25	25
Prepaid interest	-	2	2
Total cash	36	27	63
Non-cash:			
Unamortized original issue premium	(11)	(8)	(19)
Unamortized deferred loan costs	12	9	21
Total non-cash	1	1	2
Total loss on extinguishment of debt	$ 37	$ 28	$ 65

In December 2016, the Company issued $600 million in aggregate principal amount of 4.375% senior notes due 2025 at par, for which it received net proceeds of approximately $593 million. The Company used the net proceeds from the offering to fund the satisfaction and discharge of its obligations under the indenture of the $600 million outstanding principal amount of its 6.5% unsecured senior notes due 2022 (the “6.5% Notes”) at a price equal to 103.25 percent of par. The early extinguishment price included the make-whole premium as determined in accordance with the indenture governing the 6.5% Notes. In December 2016, the Company also paid interest of approximately $20 million on the 6.5% Notes through January 16, 2017.

The Company recorded a loss on extinguishment of debt related to the 6.5% Notes of approximately $28 million for the year ended December 31, 2016. This amount includes $20 million associated with the make-whole premium paid for the early extinguishment of the notes, approximately $7 million of unamortized deferred loan costs and approximately $1 million of additional interest on the 6.5% Notes through January 16, 2017, which was paid in December 2016.

In September 2016, the Company redeemed the $600 million outstanding principal amount of its 7.0% unsecured senior notes due 2021 (the “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, as determined in accordance with the indenture governing the 7.0% Notes. The Company also paid accrued and unpaid interest on the 7.0% Notes through September 19, 2016, the redemption date.

The Company recorded a loss on extinguishment of debt related to the redemption of the 7.0% Notes of approximately $28 million for the year ended December 31, 2016. This amount includes $21 million associated with the make-whole premium paid for the early redemption of the notes and approximately $7 million of unamortized deferred loan costs.

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

At December 31, 2018, 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 December 31, 2018 were as follows:

(in millions)		
2019	$	-
2020		-
2021		-
2022		242
2023		-
Thereafter		4,000
Total	$	4,242

Interest expense. The following amounts have been incurred and charged to interest expense for the years ended December 31, 2018, 2017 and 2016:

	Years Ended December 31,					
(in millions)		**2018**		**2017**		**2016**
Cash payments for interest	$	118	$	139	$	232
Non-cash interest		5		6		9
Net changes in accruals		34		4		(37)
Interest costs incurred		157		149		204
Less: capitalized interest		(8)		(3)		-
Total interest expense	$	149	$	146	$	204

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

Note 11. *Commitments and contingencies*

Severance agreements. The Company has entered into severance and change in control agreements with all of its officers. The current annual salaries for the Company's officers covered under such agreements total approximately $9 million.

Indemnifications. The Company has agreed to indemnify its directors and officers with respect to claims and damages arising from certain acts or omissions taken in such capacity.

Legal actions. The Company is a party to proceedings and claims incidental to its business. Assessing contingencies is highly subjective and requires judgment about uncertain future events. When evaluating contingencies related to legal proceedings, the Company may be unable to estimate losses due to a number of factors, including potential defenses, the procedural status of the matter in question, the presence of complex legal and/or factual issues, the ongoing discovery and/or development of information important to the matter. For material matters that the Company believes an unfavorable outcome is reasonably possible, it would disclose the nature of the matter and a range of potential exposure, unless an estimate cannot be made at this time. The Company does not believe that the loss for any other litigation matters and claims that are reasonably possible to occur will have a material adverse effect on its financial position, results of operations or liquidity. The Company will continue to evaluate proceedings and claims involving the Company on a regular basis and will establish and adjust any estimated accruals as appropriate.

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. 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.

Regulatory and environmental compliance. Regulatory liabilities relate to acquisitions where additional equipment is necessary to have facilities compliant with local, state and federal obligations. Environmental expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a noncapital nature are recorded when environmental assessment and/or remediation is probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. Environmental liabilities normally involve estimates that are subject to revision until settlement occurs. At December 31, 2018 and 2017, the Company had regulatory and environmental liabilities of approximately $26 million and $3 million, respectively, which are included in other current liabilities on the accompanying consolidated balance sheets. During the years ended December 31, 2018, 2017 and 2016, the Company recognized regulatory and environmental charges of approximately $23 million, $9 million and $7 million, respectively, which are included in oil and natural gas production expense in the accompanying consolidated statements of operations.

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

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, fixed and variable power commitments, sand commitment agreements, fixed asset commitments and maintenance commitments. The following table summarizes the Company's commitments at December 31, 2018:

(in millions)	Volume Delivery Commitments	Power Commitments (a)	Drilling Commitments and Other	Total
2019	$ 12	$ 11	$ 65	$ 88
2020	28	13	38	79
2021	29	12	35	76
2022	21	12	3	36
2023	19	12	2	33
Thereafter	73	50	7	130
Total	$ 182	$ 110	$ 150	$ 442

(a) Certain power commitments include a variable price component that is based on the last day settlement price of the NYMEX futures contract for the physical delivery period.

At December 31, 2018, the Company's delivery commitments covered the following gross volumes of oil and natural gas:

	Oil (in MMBbl)	Natural Gas (in MMcf)
2019	19	5,148
2020	38	17,321
2021	39	21,627
2022	41	16,425
2023	33	16,425
Thereafter	147	49,320
Total	317	126,266

Throughput sales commitment. In May 2018, the Company entered into a one-year term oil marketing contract with a third-party purchaser. The contract requires the Company to deliver not less than seven thousand barrels per day. Should there be a delivery shortfall in any given month, the Company retains an option to deliver the shortfall volume in any two subsequent months; however, failure to meet this volume delivery commitment would result in a penalty equal to the volume shortfall multiplied by the then market price for oil. If production is not sufficient to meet the sales commitment, the Company may purchase commodities in the market to satisfy its commitment.

114

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

Operating leases. Lease payments associated with operating leases for the year ended December 31, 2018 were approximately $13 million, $10 million and $8 million for the years ended December 31, 2017 and 2016, respectively.

Future minimum lease commitments under non-cancellable leases at December 31, 2018 were as follows:

(in millions)		
2019	$	14
2020		12
2021		10
2022		3
2023		-
Thereafter		1
Total	$	40

115

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

Note 12. ***Income taxes***

The Company uses an asset and liability approach for financial accounting and reporting for income taxes. The Company’s objectives of accounting for income taxes are to recognize (i) the amount of taxes payable or refundable for the current year and (ii) deferred tax liabilities and assets for the future tax consequences of events that have been recognized in its financial statements or tax returns. The Company and its subsidiaries file a federal corporate income tax return on a consolidated basis. The tax returns and the amount of taxable income or loss are subject to examination by federal and state taxing authorities.

The Company’s income tax expense (benefit) attributable to income (loss) from operations consisted of the following for the years ended December 31, 2018, 2017 and 2016:

	Years Ended December 31,		
(in millions)	**2018**	**2017**	**2016**
Current:			
U.S. federal	$ -	$ (6)	$ (12)
U.S. state and local	(2)	2	-
Total current income tax benefit	(2)	(4)	(12)
Deferred:			
U.S. federal	547	(94)	(771)
U.S. state and local	58	23	(93)
Total deferred income tax expense (benefit)	605	(71)	(864)
Total income tax expense (benefit)	$ 603	$ (75)	$ (876)

The reconciliation between the income tax expense (benefit) computed by multiplying pre-tax income (loss) by the U.S. federal statutory rate and the reported amounts of income tax expense (benefit) is as follows:

	Years Ended December 31,		
(in millions)	**2018**	**2017**	**2016**

Income (loss) at U.S. federal statutory rate	$	607	$	308	$	(818)
Enactment date and measurement period adjustments from the TCJA		(7)		(398)		-
State income taxes, net of federal tax effect		52		17		(41)
Change in estimated effective statutory state income tax rate		(8)		-		(21)
Excess tax benefit due to stock-based compensation		(12)		(6)		-
Research and development credits, net of unrecognized tax benefits		(41)		-		-
Other		12		4		4
Income tax expense (benefit)	$	603	$	(75)	$	(876)
Effective tax rate		21%		(9)%		38%

On December 22, 2017, the President signed into law the TCJA, which enacted significant changes to federal income tax laws, including a decrease in the federal corporate income tax rate from 35 percent to 21 percent, which was effective January 1, 2018. In accordance with SAB 118, the Company recorded, based on reasonable estimates, a $398 million decrease to its income tax provision at December 31, 2017. This provisional amount related to the re-measurement of certain deferred tax assets and liabilities based on the rates at which they are expected to reverse in the future. At December 31, 2018, the Company completed its accounting for all of the enactment-date tax effects of the TCJA and recognized an adjustment of $7 million which is included as a component of income tax expense.

The Company monitors changes in enacted tax rates for the jurisdictions in which it operates. The Company monitors its state tax apportionment footprint and makes updates for changes in its projected activity, including changes in budgets and drilling plans and changes as a result of acquisitions or divestitures. Based upon the Company’s projected future activity for the states in which it conducts business, the timing for when it anticipates its deferred tax items to become taxable and

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

enacted tax rates at such time deferred items become taxable, the Company revised its estimated state tax rate, primarily due to the impact of the RSP Acquisition. As a result, the Company recorded an income tax benefit of approximately $8 million, net of federal tax benefit, in its income tax provision for the year ended December 31, 2018. The Company did not revise its estimated state rate and, as such, did not record an additional deferred state tax benefit for the year ended December 31, 2017. The Company revised its estimated state rate and recorded a deferred state tax benefit of approximately $21 million for the year ended December 31, 2016.

The Company recorded an income tax benefit of approximately $12 million and $6 million for the years ended December 31, 2018 and 2017, respectively, related to excess tax benefits on stock-based awards, which are recorded in the income tax provision pursuant to ASU 2016-09 adopted on January 1, 2017.

At December 31, 2018, the Company had approximately $2.2 billion of federal net operating losses ("NOLs"), including $516 million acquired from RSP, net of reduction for unrecognized tax benefits. At December 31, 2018, the Company had approximately $1.5 billion of NOLs that will begin to expire in the tax year 2034 but are allowable as a deduction against 100 percent of future taxable income since they were generated prior to the effective date of the limitations imposed by the TCJA. Additionally, the Company has estimated an apportioned New Mexico NOL of approximately $520 million that will begin to expire in 2036.

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities were as follows:

	December 31,	
(in millions)	**2018**	**2017**
Deferred tax assets:		
Stock-based compensation	$ 26	$ 18
Derivative instruments	-	87
Asset retirement obligation	41	33
Net operating losses and other carryforwards	525	31
Research and development and other credits	61	-
Other	17	13
Total deferred tax assets	670	182
Less: Valuation allowance	(3)	-

Net deferred tax assets	667	182
Deferred tax liabilities:		
Oil and natural gas properties, principally due to differences in basis and depreciation and the deduction of intangible drilling costs for tax purposes	(2,270)	(852)
Intangible assets - operating rights	(4)	(5)
Derivative instruments	(158)	-
Other	(43)	(12)
Total deferred tax liabilities	(2,475)	(869)
Net deferred tax liabilities	$ (1,808)	$ (687)

On July 19, 2018, the Company completed the RSP Acquisition. For federal income tax purposes, the transaction qualified as a tax-free merger whereby the Company acquired carryover tax basis in RSP's assets and liabilities. As of December 31, 2018, the Company recorded an opening balance sheet deferred tax liability of $515 million, which includes a deferred tax asset related to tax attributes acquired from RSP. The acquired income tax attributes primarily consist of NOLs and research and development credits that are subject to an annual limitation under Internal Revenue Code Section 382. The Company expects that these tax attributes will be fully utilized prior to expiration. The Company had net deferred tax liabilities of approximately $1.8 billion and $687 million as of December 31, 2018 and 2017, respectively.

Pursuant to management's assessment, the Company does not believe a cumulative ownership change has occurred as of December 31, 2018. As such, Section 382 of the Internal Revenue Code of 1986, as amended, is not expected to limit the Company's ability to utilize its NOL carryforward as of December 31, 2018. As noted above, tax attributes acquired from RSP

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

include NOLs and credits subject to an annual limitation under Section 382; however, the Company expects that these tax attributes will be fully utilized prior to expiration.

Management monitors company-specific, oil and natural gas industry and worldwide economic factors and assesses the likelihood that the Company's NOLs and other deferred tax attributes will be utilized prior to their expiration. At December 31, 2018, management considered all factors including the expected reversal of deferred tax liabilities (including the impact of available carryforward periods), historical operating income tax planning strategies and projected future taxable income. Based on the results of the assessment, a valuation allowance of $3 million was recorded related to charitable contribution carryforwards not anticipated to be utilized prior to expiration. Management determined that it is more likely than not that the Company will realize its remaining deferred tax assets.

The following table sets forth changes in the Company's unrecognized tax benefits:

(in millions)		**December 31, 2018**
Balance at beginning of year	$	-
Increase resulting from tax positions acquired		26
Increase resulting from prior period tax positions		20
Increase resulting from current tax period positions		26
Balance at end of year		72
Less: Effects of temporary items		(9)
Total that, if recognized, would impact the effective income tax as of the end of the year	$	63

The Company recognizes the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities based upon the technical merits of the position. At December 31, 2018, the Company had unrecognized tax benefits of approximately $63 million, primarily related to research and development credits. If all or a portion of the unrecognized tax benefit is sustained upon examination by the taxing authorities, the tax benefit will be recognized as a reduction to the Company's deferred tax liability and will affect the Company's effective tax rate in the period recognized. The timing as to when the Company will substantially resolve the uncertainties associated with the unrecognized tax benefit is uncertain, but the Company does not expect that a change in the unrecognized tax benefit within the next 12 months would have a material impact to the financial statements.

The Company has not recognized any interest or penalties relating to unrecognized tax benefits in its consolidated financial statements. Any interest or penalties would be recognized as a component of income tax expense. In the Company’s major tax jurisdictions, the earliest year open to examination is 2013.

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

Note 13. ***Major customers and derivative counterparties***

Sales to major customers. The Company's share of oil and natural gas production is sold to various purchasers. The Company is of the opinion that the loss of any one purchaser would not have a material adverse effect on the ability of the Company to sell its oil and natural gas production.

The following purchasers individually accounted for 10 percent or more of the consolidated oil and natural gas revenues during the years ended December 31, 2018, 2017 and 2016:

	Years Ended December 31,		
	2018	**2017**	**2016**
Plains Marketing and Transportation, Inc.	18%	21%	29%
Holly Frontier Refining and Marketing, LLC	(a)	10%	16%

(a) This purchaser did not account for 10% or more of total revenue for the period.

At December 31, 2018, the Company had receivables from Plains Marketing & Transportation Inc. of $82 million, which are reflected in accounts receivable — oil and natural gas in the accompanying consolidated balance sheets.

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.

At December 31, 2018, the Company had a net asset position of $695 million as a result of outstanding derivative contracts which are reflected in the accompanying consolidated balance sheets. The Company assessed the balances held by each of its derivative counterparties for concentration risk and noted balances of approximately $151 million, $92 million and $84 million with JP Morgan, Citigroup and Wells Fargo, respectively.

Note 14. *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 $8 million, $7 million and $4 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

Note 15. ***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 years ended December 31, 2018, 2017 and 2016, respectively, under the two-class method:

	Years Ended December 31,		
(in millions, except per share amounts)	**2018**	**2017**	**2016**
Net income (loss) as reported	$ 2,286	$ 956	$ (1,462)
Participating basic earnings (a)	(17)	(7)	-
Basic earnings attributable to common stockholders	2,269	949	(1,462)
Reallocation of participating earnings	-	-	-
Diluted earnings attributable to common stockholders	$ 2,269	$ 949	$ (1,462)

(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.

The following table is a reconciliation of the basic weighted average common shares outstanding to diluted weighted average common shares outstanding for the years ended December 31, 2018, 2017 and 2016:

	Years Ended December 31,		
(in thousands)	**2018**	**2017**	**2016**
Weighted average common shares outstanding:			
Basic	170,925	147,320	134,755
Dilutive common stock options	-	3	-
Dilutive performance units	324	633	-
Diluted	171,249	147,956	134,755

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

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

	Years Ended December 31,		
(in thousands)	**2018**	**2017**	**2016**
Number of antidilutive common shares:			
Antidilutive performance units	108	81	-

Note 16. *Other current liabilities*

The following table provides the components of the Company's other current liabilities atDecember 31, 2018 and 2017:

	December 31,	
(in millions)	**2018**	**2017**
Other current liabilities:		
Accrued production costs	$ 135	$ 72
Payroll related matters	49	40
Accrued interest	70	36
Settlements due on derivatives	-	25
Asset retirement obligations	11	12
Other	55	31
Other current liabilities	$ 320	$ 216

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

Note 17. ***Subsidiary guarantors***

At December 31, 2018, 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 10 for a summary of the Company's senior notes. In accordance with practices accepted by the SEC, 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, certain of the Company's subsidiaries do not guarantee the Company's senior notes and are included in the Company's consolidated financial statements. These entities are 100 percent owned subsidiaries and are referred to as "Subsidiary Non-Guarantors" in the tables below. An additional entity did not guarantee the Company's senior notes at December 31, 2017. This entity was a VIE that was formed to effectuate a tax-free exchange of assets. During 2018, the Reverse Exchange 1031 was completed and all assets and liabilities attributable to the VIE were conveyed to the Company. This entity did not guarantee the Company's senior notes until the conveyance was completed. See Note 5 for additional information regarding the completion of the Reverse 1031 Exchange. The Company's less than 100 percent owned subsidiaries, primarily equity method investments, do not guarantee the Company's senior notes.

The following condensed consolidating balance sheets at December 31, 2018 and 2017, condensed consolidating statements of operations and condensed consolidating statements of cash flows for the years ended December 31, 2018, 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.

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

Condensed Consolidating Balance Sheet
December 31, 2018

(in millions)	Parent Issuer	Subsidiary Guarantors	Subsidiary Non-Guarantor	Consolidating Entries	Total
ASSETS					
Accounts receivable - related parties	$ 18,155	$ -	$ -	$ (18,155)	$ -
Other current assets	534	875	-	-	1,409
Oil and natural gas properties, net	-	21,988	17	-	22,005
Property and equipment, net	-	308	-	-	308
Investment in subsidiaries	5,411	-	-	(5,411)	-
Goodwill	-	2,224	-	-	2,224
Other long-term assets	224	124	-	-	348
Total assets	$ 24,324	$ 25,519	$ 17	$ (23,566)	$ 26,294
LIABILITIES AND EQUITY					
Accounts payable - related parties	$ -	$ 18,138	$ 17	$ (18,155)	$ -
Other current liabilities	70	1,286	-	-	1,356
Long-term debt	4,194	-	-	-	4,194
Other long-term liabilities	1,292	684	-	-	1,976
Equity	18,768	5,411	-	(5,411)	18,768
Total liabilities and equity	$ 24,324	$ 25,519	$ 17	$ (23,566)	$ 26,294

Condensed Consolidating Balance Sheet
December 31, 2017

(in millions)	Parent Issuer	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Entries	Total
ASSETS					
Accounts receivable - related parties	$ 8,836	$ (669)	$ -	$ (8,167)	$ -
Other current assets	6	576	10	-	592
Oil and natural gas properties, net	-	12,192	615	-	12,807
Property and equipment, net	-	234	-	-	234

Investment in subsidiaries		3,202		-		-		(3,202)		-
Other long-term assets		23		76		-		-		99
Total assets	$	12,067	$	12,409	$	625	$	(11,369)	$	13,732
LIABILITIES AND EQUITY										
Accounts payable - related parties	$	(669)	$	8,223	$	613	$	(8,167)	$	-
Other current liabilities		341		821		3		-		1,165
Long-term debt		2,691		-		-		-		2,691
Other long-term liabilities		789		166		6		-		961
Equity		8,915		3,199		3		(3,202)		8,915
Total liabilities and equity	$	12,067	$	12,409	$	625	$	(11,369)	$	13,732

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

Condensed Consolidating Statement of Operations
For the Year Ended December 31, 2018

(in millions)	Parent Issuer	Subsidiary Guarantors	Subsidiary Non-Guarantor	Consolidating Entries	Total
Total operating revenues	$ -	$ 4,146	$ 5	$ -	$ 4,151
Total operating costs and expenses	829	(2,047)	(3)	-	(1,221)
Income from operations	829	2,099	2	-	2,930
Interest expense	(149)	-	-	-	(149)
Other, net	2,209	108	-	(2,209)	108
Income before income taxes	2,889	2,207	2	(2,209)	2,889
Income tax expense	(603)	-	-	-	(603)
Net income	$ 2,286	$ 2,207	$ 2	$ (2,209)	$ 2,286

Condensed Consolidating Statement of Operations
For the Year Ended December 31, 2017

(in millions)	Parent Issuer	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Entries	Total
Total operating revenues	$ -	$ 2,566	$ 20	$ -	$ 2,586
Total operating costs and expenses	(129)	(1,369)	(17)	-	(1,515)
Income (loss) from operations	(129)	1,197	3	-	1,071
Interest expense	(145)	(1)	-	-	(146)
Loss on extinguishment of debt	(66)	-	-	-	(66)
Other, net	1,221	22	-	(1,221)	22
Income before income taxes	881	1,218	3	(1,221)	881
Income tax benefit	75	-	-	-	75
Net income	$ 956	$ 1,218	$ 3	$ (1,221)	$ 956

Condensed Consolidating Statement of Operations
For the Year Ended December 31, 2016

(in millions)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total

Total operating revenues	$ -	$ 1,635	$ -	$ 1,635
Total operating costs and expenses	(370)	(3,339)	-	(3,709)
Loss from operations	(370)	(1,704)	-	(2,074)
Interest expense	(202)	(2)	-	(204)
Loss on extinguishment of debt	(56)	-	-	(56)
Other, net	(1,710)	(4)	1,710	(4)
Loss before income taxes	(2,338)	(1,710)	1,710	(2,338)
Income tax benefit	876	-	-	876
Net loss	$ (1,462)	$ (1,710)	$ 1,710	$ (1,462)

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

Condensed Consolidating Statement of Cash Flows
For the Year Ended December 31, 2018

(in millions)	Parent Issuer	Subsidiary Guarantors	Subsidiary Non-Guarantor	Consolidating Entries	Total
Net cash flows provided by operating activities	$ 338	$ 2,220	$ -	$ -	$ 2,558
Net cash flows used in investing activities	-	(2,216)	-	-	(2,216)
Net cash flows used in financing activities	(338)	(4)	-	-	(342)
Net increase in cash and cash equivalents	-	-	-	-	-
Cash and cash equivalents at beginning of period	-	-	-	-	-
Cash and cash equivalents at end of period	$ -	$ -	$ -	$ -	$ -

Condensed Consolidating Statement of Cash Flows
For the Year Ended December 31, 2017

(in millions)	Parent Issuer	Subsidiary Guarantors	Subsidiary Non-Guarantors	Consolidating Entries	Total
Net cash flows provided by operating activities	$ 145	$ 1,549	$ 1	$ -	$ 1,695
Net cash flows used in investing activities	-	(1,105)	(614)	-	(1,719)
Net cash flows provided by (used in) financing activities	(145)	(497)	613	-	(29)
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
For the Year Ended December 31, 2016

(in millions)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Net cash flows provided by (used in) operating activities	$ (665)	$ 2,049	$ -	$ 1,384
Net cash flows used in investing activities	-	(2,225)	-	(2,225)
Net cash flows provided by financing activities	665	-	-	665
Net decrease in cash and cash equivalents	-	(176)	-	(176)
Cash and cash equivalents at beginning of period	-	229	-	229
Cash and cash equivalents at end of period	$ -	$ 53	$ -	$ 53

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2018, 2017 and 2016

Note 18. ***Subsequent events***

Dividends. On February 19, 2019, the Company's board of directors declared a cash dividend of $0.125 per share for the first quarter of 2019. The total cash dividend, including the cash dividend on unvested restricted stock awards, of $25 million is expected to be paid on March 29, 2019. Any payment of future dividends will be at the discretion of the Company's board of directors and will depend on, among other things, the Company's earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that the Company's board of directors deems relevant. Covenants contained in the Company's agreement governing its Credit Facility and the indentures governing the Company's senior notes could limit the payment of dividends.

Marketing contract. Consistent with the Company's strategy of diversifying its oil pricing, in January 2019, the Company entered into a firm sales agreement with a third-party purchaser. The purchaser provides an integrated transportation and marketing strategy, including ample dock capacity. The agreement has a term that ends five years after the startup of Cactus II Pipeline system and requires the Company to deliver 50,000 barrels of oil per day that will receive waterborne market pricing.

New commodity derivative contracts. After December 31, 2018, the Company entered into the following derivative contracts to hedge additional amounts of estimated future production:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Price Swaps: (a)					
2019:					
Volume (Bbl)	1,357,000	2,184,000	1,564,000	1,380,000	6,485,000
Price per Bbl	$ 54.75	$ 54.92	$ 54.51	$ 54.41	$ 54.68
2020:					
Volume (Bbl)	3,094,000	3,094,000	2,760,000	2,760,000	11,708,000
Price per Bbl	$ 54.65	$ 54.65	$ 54.61	$ 54.61	$ 54.63
2021:					
Volume (Bbl)	2,070,000	2,093,000	1,932,000	1,932,000	8,027,000
Price per Bbl	$ 54.50	$ 54.50	$ 54.42	$ 54.42	$ 54.46

Oil Basis Swaps: (b)					
2019:					
Volume (Bbl)	236,000	364,000	1,472,000	1,472,000	3,544,000
Price per Bbl	$ (2.80)	$ (2.80)	$ (1.51)	$ (1.51)	$ (1.73)
2020:					
Volume (Bbl)	2,002,000	1,547,000	1,380,000	1,380,000	6,309,000
Price per Bbl	$ (0.11)	$ (0.01)	$ 0.01	$ 0.01	$ (0.03)
2021:					
Volume (Bbl)	720,000	728,000	736,000	736,000	2,920,000
Price per Bbl	$ 0.48	$ 0.48	$ 0.48	$ 0.48	$ 0.48
Natural Gas Price Swaps: (c)					
2020:					
Volume (MMBtu)	1,820,000	1,820,000	1,840,000	1,840,000	7,320,000
Price per MMBtu	$ 2.70	$ 2.70	$ 2.70	$ 2.70	$ 2.70

(a) The oil derivative contracts are settled based on the NYMEX – WTI monthly average futures price.
(b) The basis differential price is between Midland – WTI and Cushing – WTI.
(c) The natural gas derivative contracts are settled based on the NYMEX – Henry Hub last trading day futures price.

Concho Resources Inc.

Unaudited Supplementary Data

December 31, 2018, 2017 and 2016

Capitalized costs

(in millions)	December 31, 2018		2017	
Oil and natural gas properties:				
Proved	$ 24,992		$ 18,565	
Unproved	6,714		2,702	
Less: accumulated depletion	(9,701)		(8,460)	
Net capitalized costs for oil and natural gas properties	$ 22,005		$ 12,807	(a)

(a) Approximately $135 million of the balance at December 31, 2017 relates to assets held for sale.

Costs incurred for oil and natural gas producing activities

(in millions)	Years Ended December 31, 2018	2017	2016
Property acquisition costs:			
Proved	$ 4,136	$ 303	$ 982
Unproved	3,617	905	1,154
Exploration	1,588	1,021	701
Development	1,050	653	449
Total costs incurred for oil and natural gas properties	$ 10,391	$ 2,882	$ 3,286

Concho Resources Inc.

Unaudited Supplementary Data

December 31, 2018, 2017 and 2016

Results of operations for oil and natural gas producing activities

The following table provides results of operations for the Company’s oil and natural gas producing activities and excludes amounts incurred from the Company’s non-oil and gas producing activities for the years ended December 31, 2018, 2017 and 2016:

	Years Ended December 31,		
(in millions)	**2018**	**2017**	**2016**
Oil and natural gas producing activities:			
Operating revenues:			
Oil sales	$ 3,443	$ 2,092	$ 1,350
Natural gas sales	708	494	285
Total operating revenues	4,151	2,586	1,635
Operating costs and expenses:			
Oil and natural gas production	590	408	320
Production and ad valorem taxes	305	199	131
Gathering, processing and transportation	55	-	-
Exploration and abandonments	65	59	77
Depreciation, depletion and amortization	1,478	1,146	1,167
Accretion of discount on asset retirement obligation	10	8	7
Impairments of long-lived assets	-	-	1,525
General and administrative	311	244	226
(Gain) loss on derivatives	(832)	126	369
Gain on disposition of assets, net	(800)	(23)	(118)
Total operating costs and expenses	1,182	2,167	3,704
Income (loss) before income taxes	2,969	419	(2,069)
Income tax (expense) benefit at statutory rate	(674)	(154)	759
Net income (loss)	$ 2,295	$ 265	$ (1,310)

128

Concho Resources Inc.

Unaudited Supplementary Data

December 31, 2018, 2017 and 2016

Reserve Quantity Information

The following information represents estimates of the Company's proved reserves. The pricing that was used for estimates of the Company's reserves as of December 31, 2018 was based on the SEC pricing of $62.04 per Bbl West Texas Intermediate posted oil price and $3.10 per MMBtu Henry Hub spot natural gas price.

Subject to limited exceptions, proved undeveloped reserves may only be recognized if they relate to wells scheduled to be drilled within five years of the date of their initial recognition. This rule limited, and may continue to limit, the Company's potential to record additional proved undeveloped reserves as it pursues its drilling program, particularly as it develops its significant acreage in the Permian Basin of Southeast New Mexico and West Texas. Moreover, the Company may be required to write down its proved undeveloped reserves if it does not drill on those reserves within the required five-year timeframe. All of the Company's recorded proved undeveloped reserves are scheduled to be drilled within five years of the date of their initial recognition.

The Company's proved oil and natural gas reserves are all located in the United States, primarily in the Permian Basin of Southeast New Mexico and West Texas. All of the estimates of the proved reserves at December 31, 2018, 2017 and 2016 are based on reports prepared by Cawley, Gillespie & Associates, Inc. and Netherland, Sewell & Associates, Inc., independent petroleum engineers. Proved reserves were estimated in accordance with the guidelines established by the SEC and the FASB.

The following table summarizes the prices utilized in the reserve estimates for 2018, 2017 and 2016. Commodity prices utilized for the reserve estimates prior to adjustments for location, grade and quality are as follows:

	December 31, 2018	2017	2016
Prices utilized in the reserve estimates before adjustments:			
Oil per Bbl	$ 62.04	$ 47.79	$ 39.25

Natural gas per MMBtu	$	3.10	$	2.98	$	2.48

Oil and natural gas reserve quantity estimates are subject to 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. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and natural gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

Concho Resources Inc.

Unaudited Supplementary Data

December 31, 2018, 2017 and 2016

The following table provides a rollforward of the total proved reserves for the years ended December 31, 2018, 2017 and 2016, as well as proved developed and proved undeveloped reserves at the beginning and end of each respective year.

	2018			2017			
	Oil and Condensate (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)	Oil and Condensate (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)	Oil and Condensate (MMBbls)
Total Proved Reserves:							
Balance, January 1	500	2,043	840	428	1,752	720	368
Purchases of minerals-in-place	233	449	308	22	72	34	41
Sales of minerals-in-place	(8)	(54)	(17)	(2)	(9)	(4)	(6)
Extensions and discoveries	151	452	226	115	351	174	84
Revisions of previous estimates	(65)	(58)	(74)	(20)	38	(14)	(25)
Production	(61)	(208)	(96)	(43)	(161)	(70)	(34)
Balance, December 31	750	2,624	1,187	500	2,043	840	428
Proved Developed Reserves:							
January 1	336	1,512	588	267	1,190	466	204
December 31	500	1,941	824	336	1,512	588	267
Proved Undeveloped Reserves:							
January 1	164	531	252	161	561	254	164
December 31	250	683	363	164	531	252	161

For the year ended December 31, 2018:

Extensions and discoveries. Extensions and discoveries of approximately 226 MMBoe are primarily the result of the Company’s continued success from its horizontal drilling programs in the Company’s operating areas. Proved developed reserves increased approximately 87 MMBoe due to the Company’s drilling activity in 2018. Based upon this activity, approximately 139 MMBoe of new proved undeveloped locations were added.

Purchases and sales of minerals-in-place. The Company's purchases of minerals-in-place were primarily the result of the RSP Acquisition in July 2018 which added approximately 275 MMBoe. The remainder of the purchases of minerals-in-place was primarily the result of certain acquisitions and nonmonetary transactions during 2018, which added approximately 25 MMBoe in the Midland Basin and 8 MMBoe in the Delaware Basin. The Company's sales of minerals-in-place were primarily the result of various divestitures and nonmonetary transactions during 2018.

Revisions of previous estimates. Revisions of previous estimates are primarily composed of (i) 77 MMBoe of negative revisions primarily due to proved undeveloped reserves reclassified to unproved, (ii) 15 MMBoe of net negative performance and other revisions and (iii) 18 MMBoe of positive price revisions. As the Company continues to transition its development program to large-scale projects and evaluate and analyze its producing oil and natural gas properties and drilling prospects, certain properties were no longer expected to be developed within five years of the date of their initial recognition and were removed from the Company's current drilling plans. This includes certain properties that were identified to have a lower liquids content and certain non-operated properties that the Company reclassified due to the uncertainty regarding the timing of development. Net negative performance and other revisions primarily related to 27 MMBoe of downward revisions to certain proved developed producing properties in the Yeso field, partially offset by other positive performance revisions. Positive price revisions were the result of an increase in the oil and natural gas prices utilized in the Company's reserve estimates at December 31, 2018 as compared to December 31, 2017.

For the year ended December 31, 2017:

Purchases and sales of minerals-in-place. The Company's purchases of minerals-in-place are composed of approximately 11 MMBoe from the July 2017 Midland Basin acquisition, 8 MMBoe from the January 2017 Delaware Basin acquisition and 15 MMBoe from various other acquisitions throughout the year. The Company's sales of minerals-in-place are composed of approximately 4 MMBoe from various divestitures throughout the year.

Extensions and discoveries. Extensions and discoveries of approximately 174 MMBoe are primarily the result of the Company's continued success from its extension and infill horizontal drilling programs in its operating areas. Proved

Concho Resources Inc.

Unaudited Supplementary Data

December 31, 2018, 2017 and 2016

developed reserves increased approximately 82 MMBoe due to the Company's exploratory drilling activity in 2017. Based upon this activity, approximately 92 MMBoe of new proved undeveloped locations were added.

Revisions of previous estimates. Revisions of previous estimates are composed of (i) 61 MMBoe of negative revisions due to proved undeveloped reserves reclassified to unproved reserves because they are no longer expected to be developed within five years of the date of their initial recognition as required by SEC rules due to a shift in the Company's capital program to generally focus more on large-scale development projects in certain areas, (ii) 29 MMBoe of positive price revisions and (iii) 18 MMBoe of positive technical and performance revisions.

For the year ended December 31, 2016:

Purchases and sales of minerals-in-place. The Company's purchases of minerals-in-place are composed of approximately 42 MMBoe from the October 2016 Reliance Acquisition, 15 MMBoe from the March 2016 Southern Delaware Basin acquisition and 2 MMBoe from various other acquisitions throughout the year. The Company's sales of minerals-in-place are composed of approximately 8 MMBoe from various divestitures throughout the year.

Extensions and discoveries. Extensions and discoveries of approximately 125 MMBoe are primarily the result of the Company's continued success from its extension and infill horizontal drilling programs in its operating areas. Proved developed reserves increased approximately 61 MMBoe due to the Company's exploratory drilling activity. Based upon this activity, approximately 64 MMBoe of new proved undeveloped locations were added, of which the majority are one offset location from an existing producing well.

Revisions of previous estimates. Revisions of previous estimates are comprised of (i) 57 MMBoe of negative revisions due to proved undeveloped reserves reclassified to unproved reserves because they are no longer expected to be developed within five years of the date of their initial recognition and (ii) 30 MMBoe of negative price revisions, partially offset by 63 MMBoe of net positive revisions related to lower lease operating expense estimates. The 57 MMBoe of proved undeveloped reserves in item (i) above are outside the five-year development window primarily due to results the Company has obtained during 2016 related to increased testing and implementation of new technologies that allows for drilling extended length laterals. The results are generally highly successful and provide sufficient data that substantiates drilling extended length laterals is generally a more efficient process than shorter lateral drilling to recover reserves. The results also generally confirm that the drilling of longer laterals is feasible on a large scale and substantially decreases the risks associated with a drilling program more focused on extended length laterals. Consequently, the Company shifted its capital program to focus on drilling more extended length laterals.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows is computed by applying the 12-month unweighted average of the first-day-of-the-month pricing for oil and natural gas (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved oil and natural gas reserves less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, discounted using a rate of 10 percent per year to reflect the estimated timing of the future cash flows. Future income taxes are calculated by comparing undiscounted future cash flows to the tax basis of oil and natural gas properties plus available carryforwards and credits and applying the current tax rates to the difference.

Discounted future cash flow estimates like those shown below are not intended to represent estimates of the fair value of oil and natural gas properties. Estimates of fair value would also consider probable and possible reserves, anticipated future oil and natural gas prices, interest rates, changes in development and production costs and risks associated with future production. Because of these and other considerations, any estimate of fair value is necessarily subjective and imprecise.

Concho Resources Inc.

Unaudited Supplementary Data

December 31, 2018, 2017 and 2016

The following table provides the standardized measure of discounted future net cash flows at December 31, 2018, 2017 and 2016:

(in millions)	**December 31, 2018**	**2017**	**2016**
Oil and gas producing activities:			
Future cash inflows	$ 56,621	$ 29,761	$ 20,674
Future production costs	(16,511)	(9,612)	(7,945)
Future development and abandonment costs (a)	(3,731)	(2,636)	(2,458)
Future income tax expense	(5,694)	(2,565)	(1,382)
Future net cash flows	30,685	14,948	8,889
10% annual discount factor	(15,130)	(7,470)	(4,699)
Standardized measure of discounted future net cash flows	$ 15,555	$ 7,478	$ 4,190

(a) Includes $329 million, $256 million and $231 million of undiscounted asset retirement cash outflow estimated at December 31, 2018, 2017 and 2016, respectively, using current estimates of future abandonment costs less salvage values.

Changes in Standardized Measure of Discounted Future Net Cash Flows

The following table provides a rollforward of the standardized measure of discounted future net cash flows for the years ended December 31, 2018, 2017 and 2016:

(in millions)	**Years Ended December 31, 2018**	**2017**	**2016**
Oil and natural gas producing activities:			
Purchases of minerals-in-place	$ 4,555	$ 304	$ 497
Sales of minerals-in-place	(176)	(20)	(62)
Extensions and discoveries	3,562	2,014	1,116
Development costs incurred during the period	783	619	278

Net changes in prices and production costs	2,926	1,830	(935)
Oil and natural gas sales, net of production costs	(3,201)	(1,979)	(1,184)
Changes in future development costs	304	84	591
Revisions of previous quantity estimates	(1,113)	(154)	(189)
Accretion of discount	1,001	470	405
Changes in production rates, timing and other	827	470	62
Change in present value of future net revenues	9,468	3,638	579
Net change in present value of future income tax benefit	(1,391)	(350)	(128)
	8,077	3,288	451
Balance, beginning of year	7,478	4,190	3,739
Balance, end of year	$ 15,555	$ 7,478	$ 4,190

132

Concho Resources Inc.

Unaudited Supplementary Data

December 31, 2018, 2017 and 2016

Selected Quarterly Financial Results

The following table provides selected quarterly financial results for the years ended December 31, 2018 and 2017:

	Quarter			
(in millions, except per share data)	**First**	**Second**	**Third**	**Fourth**
Year ended December 31, 2018:				
Total operating revenues	$ 947	$ 945	$ 1,192	$ 1,067
Operating costs and expenses (excluding gains (losses) on derivatives and gains on disposition of assets, net)	(620)	(610)	(787)	(836)
Gains (losses) on derivatives	(35)	(133)	(625)	1,625
Gains (losses) on disposition of assets, net	723	1	(5)	81
Income (loss) from operations	$ 1,015	$ 203	$ (225)	$ 1,937
Income tax (expense) benefit	$ (254)	$ (40)	$ 69	$ (378)
Net income (loss)	$ 835	$ 137	$ (199)	$ 1,513
Earnings per common share - Basic	$ 5.60	$ 0.92	$ (1.05)	$ 7.56
Earnings per common share - Diluted	$ 5.58	$ 0.92	$ (1.05)	$ 7.55
Year ended December 31, 2017:				
Total operating revenues	$ 612	$ 567	$ 627	$ 780
Operating costs and expenses (excluding gains (losses) on derivatives)	(492)	(508)	(511)	(556)
Gains (losses) on derivatives	286	209	(206)	(415)
Gains on disposition of assets, net	654	-	13	11
Income (loss) from operations	$ 1,060	$ 268	$ (77)	$ (180)
Income tax (expense) benefit	$ (371)	$ (93)	$ 66	$ 473
Net income (loss)	$ 650	$ 152	$ (113)	$ 267
Earnings per common share - Basic	$ 4.39	$ 1.02	$ (0.77)	$ 1.80

Earnings per common share - Diluted	$ 4.37	$ 1.02	$ (0.77)	$ 1.79

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

We had no changes in, and no disagreements with, our accountants on accounting and financial disclosure.

Item 9A. 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 Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this 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 December 31, 2018 at the reasonable assurance level.

Management's Report on Internal Control over Financial Reporting. The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed under the supervision of the Company's Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements in a timely manner. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

As of December 31, 2018, management assessed the effectiveness of the Company's internal control over financial reporting based on the criteria established in "Internal Control - Integrated Framework (2013)" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management determined that the Company maintained effective internal control over financial reporting at December 31, 2018. Management's assessment of, and conclusion on, the effectiveness of internal control over financial reporting did not include the internal controls of the entity acquired in the RSP Acquisition on July 19, 2018. RSP's total assets represented approximately 40 percent of the Company's consolidated total assets at December 31, 2018, and RSP's revenues following the July 19, 2018 acquisition date represented approximately 12 percent of the Company's consolidated total operating revenues for the year ended December 31, 2018.

Grant Thornton LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this annual report on Form 10-K, has issued its report on the effectiveness of the Company's internal control over financial reporting at December 31, 2018. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting at December 31, 2018, is included in this Item under the heading "Report of Independent Registered Public Accounting Firm."

Changes in Internal Control over Financial Reporting. Management's assessment of, and conclusion on, the effectiveness of internal control over financial reporting did not include the internal controls of the entities acquired in the RSP Acquisition. Under guidelines established by the SEC, companies are permitted to exclude acquisitions from their assessment of internal control over financial reporting for a period of up to one year following an acquisition while integrating the acquired company. We are in the process of integrating RSP's and our internal controls over financial reporting. As a result of these integration activities, certain controls will be evaluated and may be changed. Except as noted above, 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.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders

Concho Resources Inc.

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of Concho Resources Inc. (a Delaware corporation) and subsidiaries (the “Company”) as of December 31, 2018, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (“PCAOB”), the consolidated financial statements of the Company as of and for the year ended December 31, 2018, and our report dated February 20, 2019 expressed an unqualified opinion on those financial statements.

Basis for opinion

The Company’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Report on Internal Control over Financial Reporting (“Management’s Report”). Our responsibility is to express an opinion on the Company’s internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Our audit of, and opinion on, the Company's internal control over financial reporting does not include the internal control over financial reporting of RSP Permian, Inc., a wholly-owned subsidiary, whose financial statements reflect total assets and revenues constituting 40 and 12 percent, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2018. As indicated in Management's Report, RSP Permian, Inc. was acquired during 2018. Management's assertion on the effectiveness of the Company's internal control over financial reporting excluded internal control over financial reporting of RSP Permian, Inc.

Definition and limitations of internal control over financial reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma

February 20, 2019

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Item 10 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2018.

Code of Ethics. Our board of directors has adopted a financial code of ethics applicable to our Chief Executive Officer, President, Chief Financial Officer, Chief Accounting Officer and other senior financial officers, and a code of business conduct and ethics applicable to our directors, officers and employees, in accordance with applicable U.S. federal securities laws and the corporate governance rules of the NYSE (the “Codes”). The Codes can be found on our website located at *www.concho.com*. We intend to disclose future amendments to certain provisions of the Codes, and waivers of the Codes granted to executive officers and directors, on our website within four business days following the date of the amendment or waiver.

Item 11. Executive Compensation

Item 11 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2018.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Equity compensation plans. At December 31, 2018, a total of 10,500,000 shares of common stock were authorized for issuance under our equity compensation plan. In the table below, we describe certain information about these shares and the equity compensation plan which provides for their authorization and issuance. Included in column (1) are (i) unvested performance units at the maximum potential payout percentage and (ii) performance units relating to the performance period that ended on December 31, 2018 at the actual payout percentage of 175 percent. You can find descriptions of our stock incentive plan under Note 7 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

Plan category	**(1) Number of securities to be issued upon exercise of outstanding options, warrants and rights**	**(2) Weighted average exercise price of outstanding options**	**(3) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (1))**
Equity compensation plan approved by the security holders (a)	901,487	$ - (c)	1,409,581
Equity compensation plan not approved by the security holders (b)	-	$ -	-
Total	901,487		1,409,581

(a) 2015 Stock Incentive Plan. See Note 7 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

(b) None.

(c) Performance unit awards do not have an exercise price and, therefore, have been excluded from the weighted average exercise price calculation in column (2).

The remaining information required by Item 12 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2018.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Item 13 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2018.

Item 14. Principal Accounting Fees and Services

Item 14 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2018.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) Listing of Financial Statements

Financial Statements

The following consolidated financial statements are included in “Item 8. Financial Statements and Supplementary Data”:

Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheets at December 31, 2018 and 2017

Consolidated Statements of Operations for the Years Ended December 31, 2018, 2017 and 2016

Consolidated Statements of Stockholders’ Equity for the Years Ended December 31, 2018, 2017 and 2016

Consolidated Statements of Cash Flows for the Years Ended December 31, 2018, 2017 and 2016

Notes to Consolidated Financial Statements

Unaudited Supplementary Data

(b) Exhibits

The exhibits to this report required to be filed pursuant to Item 15(b) are listed below and in the “Index to Exhibits” attached hereto.

(c) Financial Statement Schedules

No financial statement schedules are required to be filed as part of this report or they are inapplicable.

Exhibits

Exhibit

Number
Description

2.1 Agreement and Plan of Merger among Concho Resources Inc., RSP Permian, Inc. and Green Merger Sub Inc., dated as of March 27, 2018 (filed as Exhibit 2.1 to the Company’s Current Report on Form 8-K on March 28, 2018, and incorporated herein by reference).

3.1 Restated Certificate of Incorporation of Concho Resources Inc. (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 Fourth Amended and Restated Bylaws of Concho Resources Inc., as amended January 2, 2018 (filed as Exhibit 3.1 to the Company’s Current Report on Form 8-K on January 4, 2018, 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 Senior Indenture, dated September 18, 2009, between 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 22, 2009, and incorporated herein by reference).

4.3 Tenth Supplemental Indenture, dated December 28, 2016, between 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 December 28, 2016, and incorporated herein by reference).

4.4 Eleventh Supplemental Indenture, dated January 25, 2017, among Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.4 to the Company's Registration Statement on Form S-3 on June 14, 2018, and incorporated herein by reference).

4.5 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).

4.6 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).

4.7 Fourteenth Supplemental Indenture, dated July 2, 2018, 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 July 2, 2018, and incorporated herein by reference).

4.8 Fifteenth Supplemental Indenture, dated July 2, 2018, 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 July 2, 2018, and incorporated herein by reference).

4.9 Sixteenth Supplemental Indenture, dated August 14, 2018, 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 August 15, 2018, and incorporated herein by reference).

10.1 ** Form of Performance Unit Award Agreement (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on January 4, 2013, and incorporated herein by reference).

10.2 ** Form of Performance Unit Award Agreement, dated January 2, 2019 (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on January 4, 2019, and incorporated herein by reference).

10.3 ** Performance Unit Award Agreement, dated January 2, 2018, by and between Concho Resources Inc. and E. Joseph Wright (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on January 4, 2018, and incorporated herein by reference).

10.4 ** Concho Resources Inc. 2015 Stock Incentive Plan (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on June 5, 2015, and incorporated herein by reference).

10.5 ** Form of Nonstatutory Stock Option Agreement (filed as Exhibit 10.16 to the Company's Annual Report on Form 10-K on March 28, 2008, and incorporated herein by reference).

10.6 ** Form of Restricted Stock Agreement (for officers) (filed as Exhibit 10.1 to the Company's Annual Report on Form 10-K on February 22, 2013, and incorporated herein by reference).

10.7 ** Form of Restricted Stock Agreement (for non-employee directors) (filed as Exhibit 10.18 to the Company’s Annual Report on Form 10-K on March 28, 2008, and incorporated herein by reference).

10.8 ** Restricted Stock Agreement, dated January 2, 2018, between Concho Resources Inc. and E. Joseph Wright (filed as Exhibit 10.2 to the Company’s Current Report on Form 8-K on January 4, 2018, and incorporated herein by reference).

10.9 ** Form of Restricted Stock Agreement (filed as Exhibit 10.3 to the Company’s Current Report on Form 8-K on January 4, 2019, and incorporated herein by reference).

10.10 ** Form of Succession Restricted Stock Agreement (filed as Exhibit 10.4 to the Company’s Current Report on Form 8-K on January 4, 2019, and incorporated herein by reference).

10.11 ** Employment Agreement, dated January 1, 2019, by and between Concho Resources Inc. and J. Steve Guthrie (filed as Exhibit 10.8 to the Company's Current Report on Form 8-K on January 4, 2019, and incorporated herein by reference).

10.12 ** Form of Indemnification Agreement, dated March 27, 2017, between Concho Resources Inc. and Susan J. Helms (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on March 28, 2017, and incorporated herein by reference).

10.13 ** Form of Indemnification Agreement, dated January 2, 2019, between Concho Resources Inc. and each of the officers and directors thereof (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on January 4, 2019, and incorporated herein by reference).

10.14 ** Retirement Agreement, dated May 17, 2017, by and between Concho Resources Inc. and E. Joseph Wright (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on May 19, 2017, and incorporated herein by reference).

10.15 ** Performance Unit Award Agreement, dated January 2, 2018, by and between Concho Resources Inc. and E. Joseph Wright (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on January 4, 2018, and incorporated herein by reference).

10.16 ** Form of Succession 3-Year Performance Unit Award Agreement, dated January 2, 2019, between Concho Resources Inc. and each of Messrs. Harper and Giraud (filed as Exhibit 10.5 to the Company's Current Report on Form 8-K on January 4, 2019, and incorporated herein by reference).

10.17 ** Form of Succession 5-Year Performance Unit Award Agreement, dated January 2, 2019, between Concho Resources Inc. and each of Messrs. Harper and Giraud (filed as Exhibit 10.6 to the Company's Current Report on Form 8-K on January 4, 2019, and incorporated herein by reference).

10.18 ** Restricted Stock Agreement, dated January 2, 2018, between Concho Resources Inc. and E. Joseph Wright (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on January 4, 2018, and incorporated herein by reference).

10.19 Second Amended and Restated Credit Agreement, dated as of May 9, 2014, among Concho Resources Inc., the lenders party thereto, JPMorgan Chase Bank, N.A., as administrative agent, and the co-syndication agents and co-documentation agents named therein (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q on May 12, 2014, and incorporated herein by reference).

10.20 First Amendment to Second Amended and Restated Credit Agreement, dated as of April 8, 2015, among Concho Resources Inc., the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on April 9, 2015, and incorporated herein by reference).

10.21 Second Amendment to Second Amended and Restated Credit Agreement, dated as of April 12, 2017, among Concho Resources Inc., the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q on August 3, 2017, and incorporated herein by reference).

10.22 Securities Purchase Agreement, dated January 19, 2017, between COG Operating LLC, as seller, and Plains Pipeline, L.P., as purchaser (filed as Exhibit 10.1 to the Company's Quarterly

Report on Form 10-Q on May 4, 2017, and incorporated herein by reference).

10.23 Non-Competition, Non-Solicitation and Confidentiality Agreement, dated July 18, 2018 by and between RSP Permian, Inc., Concho Resources Inc. and Steven Gray (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q on August 2, 2018, and incorporated herein by reference).

10.24 ** Executive Severance Plan, dated January 1, 2019, by and between Concho Resources Inc. and each of the officers thereof (filed as Exhibit 10.7 to the Company's Current Report on Form 8-K on January 4, 2019, and incorporated herein by reference).

21.1 (a) Subsidiaries of Concho Resources Inc.

23.1 (a) Consent of Grant Thornton LLP.

23.2 (a) Consent of Netherland, Sewell & Associates, Inc.

23.3 (a) Consent of Cawley, Gillespie & Associates, Inc.

31.1 (a) Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.

31.2 (a) Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.

32.1 (b) Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350.

32.2 (b) Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350.

99.1 (a) Netherland, Sewell & Associates, Inc. Reserve Report, dated January 21, 2019.

99.2 (a) Cawley, Gillespie & Associates, Inc. Reserve Report, dated January 23, 2019.

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.

** Management contract or compensatory plan or agreement.

Item 16. Form 10-K Summary

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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:	February 20, 2019	By	/s/ Timothy A. Leach
			Timothy A. Leach Chairman of the Board of Directors and Chief Executive Officer (Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ TIMOTHY A. LEACH Timothy A. Leach	Chairman of the Board of Directors and Chief Executive Officer (Principal Executive Officer)	February 20, 2019
/s/ BRENDA R. SCHROER Brenda R. Schroer	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)	February 20, 2019
/s/ JACOB P. GOBAR Jacob P. Gobar	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 20, 2019
/s/ STEVEN L. BEAL Steven L. Beal	Director	February 20, 2019
/s/ TUCKER S. BRIDWELL Tucker S. Bridwell	Director	February 20, 2019
/s/ WILLIAM H. EASTER III William H. Easter III	Director	February 20, 2019
/s/ STEVEN D. GRAY Steven D. Gray	Director	February 20, 2019
/s/ SUSAN J. HELMS Susan J. Helms	Director	February 20, 2019
/s/ GARY A. MERRIMAN Gary A. Merriman	Director	February 20, 2019
/s/ MARK B. PUCKETT Mark B. Puckett	Director	February 20, 2019
/s/ JOHN P. SURMA John P. Surma	Director	February 20, 2019
/s/ E. JOSEPH WRIGHT E. Joseph Wright	Director	February 20, 2019