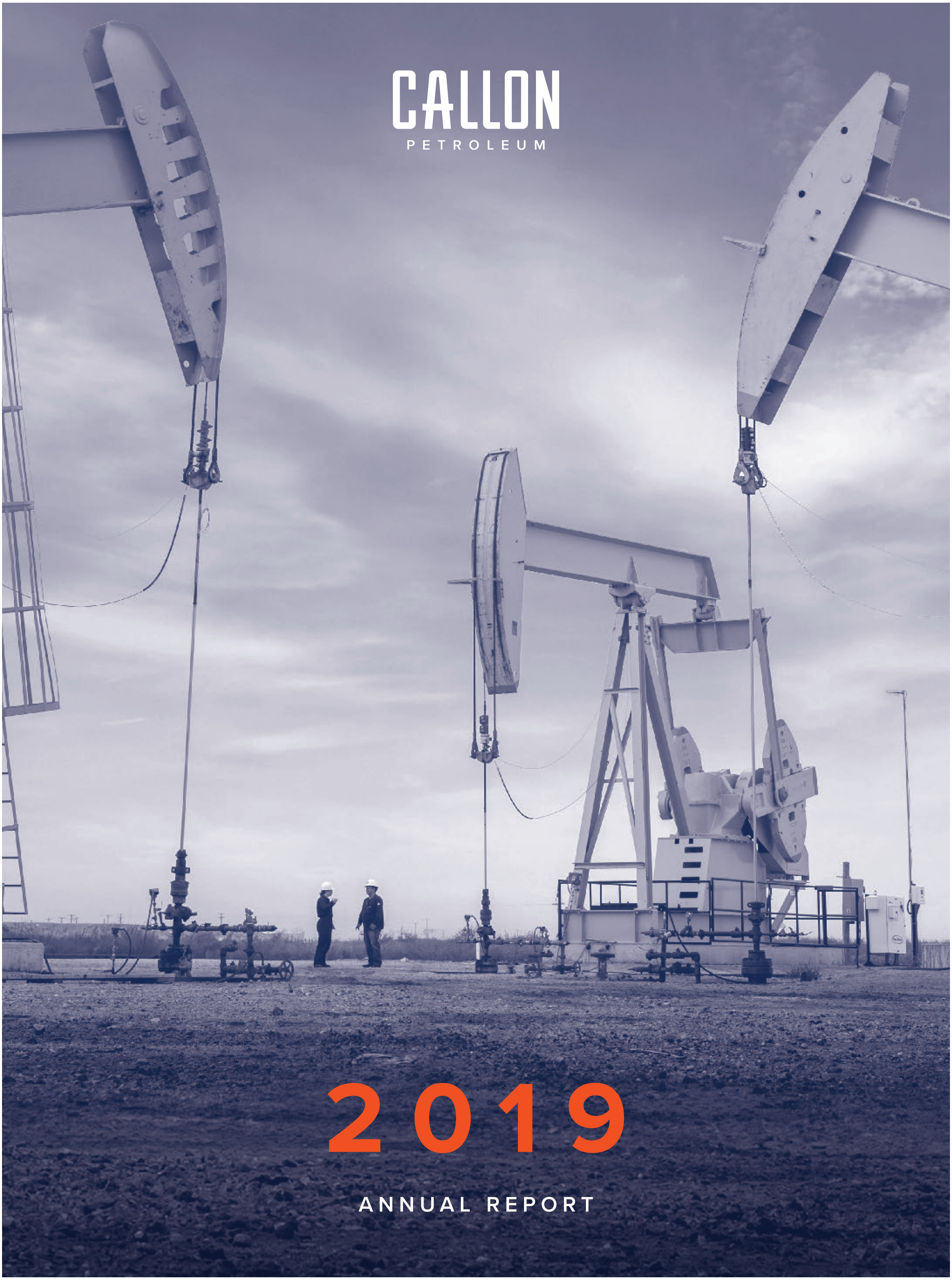
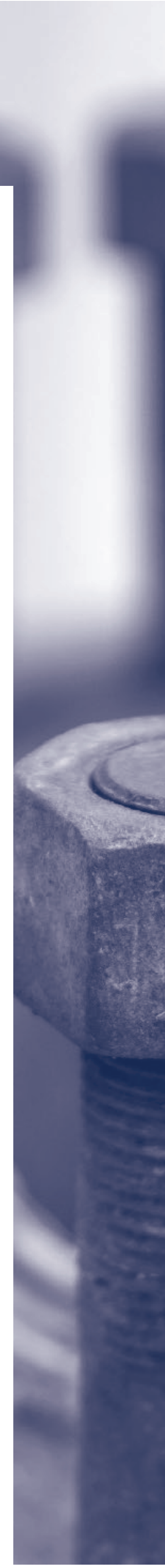


CALLON
PETROLEUM

2019

ANNUAL REPORT

FOCUSED



Callon Petroleum is an independent oil and natural gas company focused on the acquisition, exploration, and development of high-quality assets in the leading oil plays of the Permian Basin in West Texas and Eagle Ford Shale in South Texas. Our mission is to build trust, create value, and drive sustainable growth for our investors, our employees, and the communities in which we operate.

2019 HIGHLIGHTS

39%

MULTI-YEAR PRODUCTION CAGR

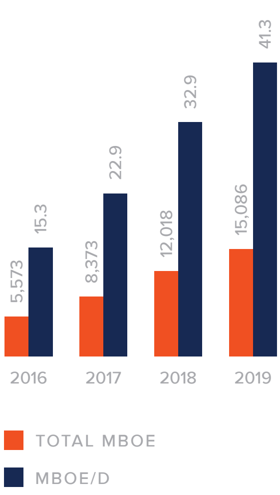
81%

MULTI-YEAR RESERVES GROWTH CAGR

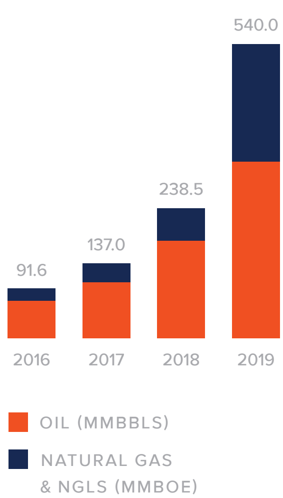
75%

MULTI-YEAR PDP CAGR

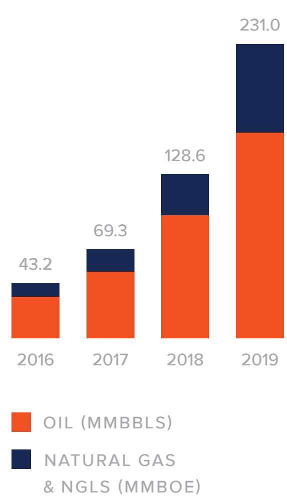
PRODUCTION



PROVED RESERVES



PDP RESERVES



DEAR SHAREHOLDERS,

2019 was a transformational year for Callon. Our advancement of critical strategic initiatives has increased our capital efficiency and is supporting our path towards sustainable, long-term development of our expanded asset base. The important landmarks of this past year include:

- Expanded acreage position to nearly 200,000 net acres in Texas' producer-friendly Permian Basin and Eagle Ford Shale through our Carrizo acquisition
- Generated over $500 million in adjusted EBITDA[1]
- Completed approximately $300 million of non-core asset monetizations
- Redeemed approximately $270 million of preferred securities, resulting in go-forward dividend savings of nearly $25 million annually
- Maintained an industry-leading EBITDA margin of $33.28 per Boe for 2019[1]
- Grew total proved reserves to 540 million Boe with a PV-10 value of $5.4 billion[1]
- Generated $58.2 million in free cash flow during the 4th quarter of 2019 (on a pro forma basis)[2]
- Increased recycled water volumes by 2x from 2018, further reducing environmental impact of operations
- Reduced flaring intensity by more than 40% year-over-year in 2019[3]
- Achieved record safety performance metrics, including a Total Recordable Incident Rate (TRIR) that was 50% lower than the prior year[4]
- Added three new independent directors, including our second female director on an 11-person board

[1]Please see reconciliation of Non-GAAP financial measures. [2]Free cash flow defined as Adjusted EBITDA minus the sum of operational capital, capitalized interest, capitalized G&A, and interest expense. Adjusted EBITDA is a non-GAAP financial measure; please refer to reconciliation of Non-GAAP Financial Measures. [3]TX RRC (Texas Railroad Commission) defines flare intensity as gross daily flare volumes divided by gross daily oil production. Callon calculated flare intensity of 8% in 2019 is below the 10% benchmark set by the Texas Railroad Commission. [4]Defined as incidents per 200,000 man hours, inclusive of contractor performance.

STRATEGIES

COMPLEMENTARY

Today, we stand with a Permian footprint of almost 120,000 net acres, complemented by approximately 80,000 net acres in the Eagle Ford Shale.

Our drilling inventory is made up of projects with a balance of capital intensity and cycle times that position us to unlock a substantial Permian value proposition. Given recent events, this increased flexibility in our capital allocation is likely one of the most valuable aspects of our recent corporate combination. The coming months will require a thoughtful approach to navigating a depressed commodity price environment, something we have been successful in doing before and are well prepared to do again.

Having weathered numerous low-price environments over our 70 year history, we understand that the best positioned companies are those with strong asset bases and robust cash margins, combined with a proven ability to be nimble. Our initial program this year was demonstrative of the rapid pace of operational and cost synergies we are able to attain, and placed us in a position to drive improved corporate returns and focus on free cash flow. While the near-term commodity pricing makes that a more challenging goal, our cost structure will allow us to preserve value and maintain a resilient base of production and cash flow until commodity markets normalize. Our diversified portfolio provides us with an advantage over many of our peers, providing us the opportunity to shift capital allocation to balance near-term returns and long-term asset value as market dynamics shift during periods of price volatility. With an inventory of approximately 2,300 net potential drilling locations, we currently have core positions in the three lowest-cost resource plays in North America. As a combined company, we have compressed cycle times, which allows our crews to be more efficient and reduces the number of teams required in the field. We have also been able to plan and consolidate activity to more effectively reduce the offset impact to existing wells. This is truly evident when we look at our wells by basin and the cost reductions we have realized thus far.

ASSETS

DELAWARE BASIN

- Long-term growth driver through co-development opportunities
- Ample organic inventory upside through stacked pay delineation

MIDLAND BASIN

- Co-development of high return multi-zone inventory
- Streamlined operations into manufacturing mode

EAGLE FORD SHALE

- Highly efficient cash flow machine with repeatable, low-risk inventory
- Lower capital intensity projects provide balance within broader company portfolio

DURABLE

Investors have continued to express their desire for our industry to live within its means while balancing growth and returns. For 2020, our focus will be on protecting our cash flows, our balance sheet, and our shareholder returns over the long term. In light of unprecedented externalities impacting our industry, we have elected to decelerate our pace of development activity given the decline in commodity prices, and reduce our planned drilling and completion spending. We will be directing an increased proportion of our capital program towards the Midland Basin and Eagle Ford Shale, where shorter cycle, high-margin, higher-return opportunities will improve cash conversion cycles and advance our financial objectives. While we won't be investing as much as initially planned in the Delaware Basin this year, our asset base in this region will be a key driver of sustained returns on capital from larger scale co-development projects targeting multiple zones of resource.

These accomplishments are the result of great people working towards a common goal. Once again, we were selected as a "Top Workplace" by the *Houston Chronicle* this year by our employees. We have always viewed our people as our most valuable asset. Importantly, our company has benefited from the addition of experienced personnel throughout each level from the legacy Carrizo organization, a key strategic element of our recent combination.

Challenging times for our industry clearly highlight the reality that we are price takers as commodity producers. As we cannot fully control the macro uncertainty inherent in a cyclical commodity business, we need to be a low-cost producer with "all-in" corporate cash break-even costs below the marginal cost of supply. Our high-quality asset base and the efficiencies we have realized as we have grown as an unconventional operator, both dramatically enhanced by the Carrizo transaction, have firmly positioned us as a low-cost producer with the ability to weather this most recent storm. Longer-term, our efficient operating model will drive corporate-level returns to align our purpose with that of our stakeholders.

RETURNS

SUSTAINABLE

At Callon, our commitment to our shareholders is simple: create value in a responsible manner. Our focus on integrating sustainable business practices and achieving long-term results drives our operations. The entire team is committed to driving returns for our shareholders, while positively impacting the communities in which we live and work.

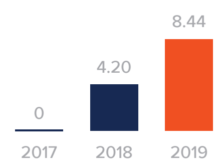
Corporate sustainability is critical to our ability to compete in the market, and something we have been working hard to incorporate into each of the facets of our business. It has to account for not only our impact on the environment, but how we view our human capital and oversee our strategic processes. In addition, as managers of our business, we must hold ourselves responsible for achieving positive outcomes that are transferred to our shareholders.

We are proud of our sustainability achievements during 2019 and look forward to building on our successes in the new year.

ENVIRONMENTAL

- 60% produced water sourced for Delaware completions
- 40% reduction in gas flaring intensity[1]
- >90% of crude and water transported via pipeline
- <20% permitted water infrastructure utilization rate in the Permian Basin minimizes future environmental impact
- Decreased total fluid spill rate by ~50%

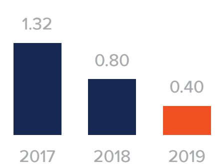
TOTAL RECYCLED WATER VOLUMES (MM BBLS)



SOCIAL

- 50% reduction in TRIR (2019 best year on record for safety performance)
- Named “Top Workplace” by *Houston Chronicle* 3 years in a row
- Employee matching program for charitable giving

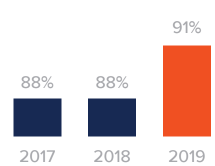
RECORD TRIR SAFETY PERFORMANCE[2]



GOVERNANCE

- Two female Directors
- Less than 5-year tenure for over half the Directors
- Independent, non-executive director serves as chair of the Board

PERCENTAGE OF INDEPENDENT DIRECTORS



[1]TX RRC (Texas Railroad Commission) defines flare intensity as gross daily flare volumes divided by gross daily oil production. Callon calculated flare intensity of 8% in 2019 is below the 10% benchmark set by the Texas Railroad Commission. [2]Defined as incidents per 200,000 man hours, inclusive of contractor performance.

INITIATIVES

GRATITUDE

This past year saw the team here at Callon and our new staff from Carrizo work tirelessly to advance a strategic combination that has created a more durable, efficient, and competitive entity against the backdrop of global economic weakness. This industry has always been demanding on a day-to-day basis, but to couple that commitment with the extraordinary amount of work required to complete a major corporate merger is a truly daunting task. I am extremely proud of all of our employees, those who will carry on the Callon legacy as well as those who have gotten us to this point, and could not be more thankful for your tireless efforts, late nights, and positive attitudes as we continue to build upon the success we have achieved over the past few years.

The path forward for Callon and the industry as a whole will be defined by our ability to address the challenges of the current environment. It will require us to be focused on making the most of every dollar of capital we spend. We have all seen how severe commodity shifts have affected the sector in recent years, but the companies that have made the tough decisions and fought to preserve value have been rewarded when the winds of change began to shift. I want to thank all of our employees and contractors, whose efforts, as well as willingness to embrace transformational change, have helped build Callon into a company that is well positioned for continued success.

JOSEPH C. GATTO JR.
PRESIDENT AND CHIEF EXECUTIVE OFFICER


FORM 10-K

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, 2019
or
☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from ___________ to ___________
Commission File Number 001-14039

Callon Petroleum Company

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**64-0844345**
State or Other Jurisdiction of Incorporation or Organization	I.R.S. Employer Identification No.
One Briarlake Plaza 2000 W. Sam Houston Parkway S., Suite 2000 Houston, Texas	**77042**
Address of Principal Executive Offices	Zip Code

281-589-5200
(Registrant's Telephone Number, Including Area Code)

Title of Each Class	Securities registered pursuant to Section 12(b) of the Act:	Name of Each Exchange on Which Registered
Common Stock, $0.01 par value	CPE	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 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 ☒

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2019 was approximately $1.5 billion.

The Registrant had 396,684,449 shares of common stock outstanding as of February 21, 2020**.**

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive Proxy Statement of Callon Petroleum Company (to be filed no later than 120 days after December 31, 2019) relating to the Annual Meeting of Stockholders to be held on May 14, 2020, which are incorporated into Part III of this Form 10-K.

TABLE OF CONTENTS

Special Note Regarding Forward Looking Statements

This report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 (the "Securities Act"), as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). These statements involve known and unknown risks, uncertainties and other factors that may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In some cases, you can identify forward-looking statements in this Form 10-K by words such as "anticipate," "project," "intend," "estimate," "expect," "believe," "predict," "budget," "projection," "goal," "plan," "forecast," "target" or similar expressions.

All statements, other than statements of historical facts, included in this report that address activities, events or developments that we expect or anticipate will or may occur in the future are forward-looking statements, including such things as:

- matters relating to the acquisition of Carrizo Oil & Gas, Inc. ("Carrizo");
- our oil and natural gas reserve quantities, and the discounted present value of these reserves;
- the amount and nature of our capital expenditures;
- our future drilling and development plans and our potential drilling locations;
- the timing and amount of future capital and operating costs;
- production decline rates from our wells being greater than expected;
- commodity price risk management activities and the impact on our average realized prices;
- business strategies and plans of management;
- our ability to consummate and efficiently integrate recent acquisitions; and
- prospect development and property acquisitions.

We caution you that the forward-looking statements contained in this Annual Report on Form 10-K (this "2019 Annual Report on Form 10-K") are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of oil and natural gas. We disclose these and other important factors that could cause our actual results to differ materially from our expectations under "Risk Factors" in Item 1A of Part I in this 2019 Annual Report on Form 10-K. These factors include:

- general economic conditions including the availability of credit and access to existing lines of credit;
- the volatility of oil and natural gas prices;
- the uncertainty of estimates of oil and natural gas reserves;
- impairments;
- the impact of competition;
- the availability and cost of seismic, drilling and other equipment, waste and water disposal infrastructure, and personnel;
- operating hazards inherent in the exploration for and production of oil and natural gas;
- difficulties encountered during the exploration for and production of oil and natural gas;
- the potential impact of future drilling on production from existing wells
- difficulties encountered in delivering oil and natural gas to commercial markets;
- changes in customer demand and producers' supply;
- the uncertainty of our ability to attract capital and obtain financing on favorable terms;
- compliance with, or the effect of changes in, the extensive governmental regulations regarding the oil and natural gas business including those related to climate change and greenhouse gases;
- the impact of government regulation, including regulation of hydraulic fracturing and water disposal wells;
- any increase in severance or similar taxes;
- the financial impact of accounting regulations and critical accounting policies;
- the comparative cost of alternative fuels;
- credit risk relating to the risk of loss as a result of non-performance by our counterparties;
- cyberattacks on the Company or on systems and infrastructure used by the oil and natural gas industry;
- weather conditions;
- risks associated with acquisitions, including the acquisition of Carrizo (the "Carrizo Acquisition" or the "Merger");
- failure to realize the expected benefits of the Carrizo Acquisition;
- any litigation relating to the Carrizo Acquisition; and
- any other factors listed in the reports we have filed and may file with the SEC.

Should one or more of these risks or uncertainties occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. Additional risks or uncertainties that are not currently known to us, that we currently deem to be immaterial, or that could apply to any company could also materially adversely affect our business, financial condition, or future results. Any forward-looking statement speaks only as of the date of which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except required by applicable law.

In addition, we caution that reserve engineering is a process of estimating oil and natural gas accumulated underground and cannot be measured exactly. Accuracy of reserve estimates depend on a number of factors including data available at the point in time, engineering interpretation of the data, and assumptions used by the reserve engineers as it relates to price and cost estimates and recoverability. New results of drilling, testing, and production history may result in revisions of previous estimates and, if significant, would impact future development plans. As such, reserve estimates may differ from actual results of oil and natural gas quantities ultimately recovered.

Except as required by applicable law, all forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

GLOSSARY OF CERTAIN TERMS

All defined terms under Rule 4-10(a) of Regulation S-X shall have their prescribed meanings when used in this report. As used in this document:

- **ARO**: asset retirement obligation.
- **ASU**: accounting standards update.
- **Bbl** or **Bbls**: barrel or barrels of oil or natural gas liquids.
- **Boe**: barrel of oil equivalent, determined by using the ratio of one Bbl of oil or NGLs to six Mcf of natural gas. The ratio of one barrel of oil or NGLs to six Mcf of natural gas is commonly used in the industry and represents the approximate energy equivalence of oil or NGLs to natural gas, and does not represent the economic equivalency of oil and NGLs to natural gas. The sales price of a barrel of oil or NGLs is considerably higher than the sales price of six Mcf of natural gas.
- **Boe/d**: Boe per day.
- **BLM**: Bureau of Land Management.
- **Btu**: a British thermal unit, which is a measure of the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.
- **Completion**: the process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.
- **Cushing**: an oil delivery point that serves as the benchmark oil price for West Texas Intermediate.
- **Development well**: A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.
- **EPA**: United States Environmental Protection Agency.
- **Exploratory well**: A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir.
- **FASB**: Financial Accounting Standards Board.
- **GAAP**: Generally Accepted Accounting Principles in the United States.
- **GHG**: greenhouse gases.
- **Henry Hub**: a natural gas pipeline delivery point that serves as the benchmark natural gas price underlying NYMEX natural gas futures contracts.
- **Horizontal drilling**: a drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at an angle within a specified interval.
- **ICE:** Intercontinental Exchange.
- **LIBOR**: London Interbank Offered Rate.
- **LOE**: lease operating expense.
- **MBbls**: thousand barrels of oil.
- **MBoe**: thousand Boe.
- **Mcf**: thousand cubic feet of natural gas.
- **MEH**: Magellan East Houston, a delivery point in Houston, Texas that serves as a benchmark for crude oil.
- **MMBoe**: million Boe.
- **MMBtu**: million Btu.
- **MMcf**: million cubic feet of natural gas.
- **NGL or NGLs**: natural gas liquids, such as ethane, propane, butanes and natural gasoline that are extracted from natural gas production streams.
- **Non-productive well**: A well that is found to be incapable of producing oil or gas in sufficient quantities to justify completion, or upon completion, the economic operation of an oil or gas well.
- **NYMEX**: New York Mercantile Exchange.
- **Oil**: includes crude oil and condensate.
- **OPEC**: Organization of Petroleum Exporting Countries.
- **PDPs**: proved developed producing reserves.
- **Productive well**: A well that is found to be capable of producing oil or gas in sufficient quantities to justify completion as an oil or gas well.
- **Proved developed producing reserves:** Proved reserves that can be expected to be recovered 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.
- **Proved reserves:** Those reserves 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.

The area of the reservoir considered as proved includes all of the following:

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 gas on the basis of available geoscience and engineering data.

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

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.

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 before 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 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. 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. 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, unless specific circumstances justify a longer time. Under no circumstances shall estimates of proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.
- **PUDs**: proved undeveloped reserves.
- **PV-10 (Non-GAAP)**: the present value of estimated future gross revenue to be generated from the production of estimated net proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date indicated (unless such prices or costs are subject to change pursuant to contractual provisions), without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization, discounted using an annual discount rate of 10 percent. While this measure does not include the effect of income taxes as it would in the use of the standardized measure of discounted future net cash flows calculation, it does provide an indicative representation of the relative value of the Company on a comparative basis to other companies from period to period. This is a non-GAAP measure. See “Items 1 and 2 - Business and Properties - Proved Oil and Gas Reserves - Reconciliation of Standardized Measure of Discounted Future Net Cash Flows (GAAP) to PV-10 (Non-GAAP)”.
- **Realized price**: the cash market price less all expected quality, transportation and demand adjustments.
- **Royalty interest**: an interest that gives an owner the right to receive a portion of the resources or revenues without having to carry any costs of development.
- **RSU**: restricted stock units.
- **SEC**: United States Securities and Exchange Commission.
- **Waha**: a natural gas delivery point in West Texas that serves as the benchmark for natural gas.
- **Working interest**: an operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.
- **WTI**: West Texas Intermediate grade crude oil, used as a pricing benchmark for sales contracts and NYMEX oil futures contracts.

With respect to information relating to our working interest in wells or acreage, “net” oil and gas wells or acreage is determined by multiplying gross wells or acreage by our working interest therein. Unless otherwise specified, all references to wells and acres are gross.

PART I.

ITEMS 1 and 2 – Business and Properties

Overview

Callon Petroleum Company has been engaged in the exploration, development, acquisition and production of oil and natural gas properties since 1950. As used herein, the “Company,” “Callon,” “we,” “us,” and “our” refer to Callon Petroleum Company and its predecessors and subsidiaries unless the context requires otherwise. We were incorporated in the state of Delaware in 1994.

We are an independent oil and natural gas company focused on the acquisition, exploration and development of high-quality assets in the leading oil plays of South and West Texas. Our activities are primarily focused on horizontal development in the Midland and Delaware Basins, both of which are part of the larger Permian Basin in West Texas. In 2019, though our acquisition of Carrizo, we double our core acreage position in the Delaware Basin and entered the Eagle Ford Shale. Our primary operations in the Permian Basin reflect a high-return, oil-weighted drilling inventory with multiple prospective horizontal development intervals and are complemented by a well-established and repeatable free cash flow generating business in the Eagle Ford Shale.

Major Developments in 2019

Merger with Carrizo Oil & Gas, Inc. On December 20, 2019, we completed our acquisition of Carrizo, in an all-stock transaction. The addition of Carrizo’s assets increased our portfolio to: (i) over 116,000 net acres in the Permian Basin, which doubled our footprint in the Southern Delaware Basin and (ii) expanded our portfolio to include over 76,000 net acres in the mature, high-margin, free cash flow generating Eagle Ford Shale.

Ranger Divestiture. On June 12, 2019, we completed our divestiture of certain non-core assets in the southern Midland Basin (the “Ranger Divestiture”) for net cash proceeds of $244.9 million. The transaction also provided for potential additional contingent consideration to be paid to us of up to $60.0 million based on West Texas Intermediate average annual pricing over a three-year period. The divestiture encompassed the Ranger operating area in the southern Midland Basin which included approximately 9,850 net Wolfcamp acres with an average 66% working interest.

See “Note 4 - Acquisitions and Divestitures” of the Notes to our Consolidated Financial Statements for further discussion.

Financing and Liquidity Activity. In connection with the Carrizo Acquisition, we entered into a credit agreement with a syndicate of lenders (the “Credit Facility”), which has a maximum credit amount of $5.0 billion. As of December 31, 2019, the borrowing base under the Credit Facility was $2.5 billion, with an elected commitment amount of $2.0 billion. During 2019, we also redeemed the remaining outstanding 10% Series A Cumulative Preferred Stock (“Preferred Stock”) for a total redemption price of $73.0 million.

See “Note 7 – Borrowings” and “Note 11 – Stockholders’ Equity” of the Notes to our Consolidated Financial Statements for further discussion.

Operational Activity. Our drilling activity during 2019 was predominantly associated with the horizontal development of several prospective intervals in the Permian Basin, including multiple levels of the Wolfcamp formation and the Lower Spraberry shales, as well as the Eagle Ford Shale, which we entered into in late 2019 as a result of the Carrizo Acquisition. As a result of our horizontal development efforts and contributions from acquisitions, our net daily production for the year ended December 31, 2019 as compared to the prior year grew approximately 26% to 41,331 Boe/d (approximately 77% oil). For the year ended December 31, 2019, our estimated proved reserves were 540.0 MMBoe, an increase of 126% as compared to the year ended December 31, 2018 primarily as a result of the merger with Carrizo described above, and included proved oil reserves of 346.4 MMBbls (64% of total proved reserves). Approximately 43% of our 2019 year-end estimated proved reserves were classified as proved developed.

We intend to grow our reserves and production through the drilling and development of our multi-year inventory of identified drilling locations. We will also seek to grow our inventory of locations through delineation of emerging zones and selective “bolt-on” acquisition and leasing programs in areas complementary to our core operating areas.

Our Business Strategy

Our principal objective is to enhance shareholder value through capital efficient growth in proved reserves and associated production and cash flows while acting as a responsible corporate citizen in the areas in which we operate. Key elements of the execution of this strategy include:

- Optimizing the development of our multi-zone resource base through thoughtful plans of development that are educated by extensive analysis of subsurface data and empirical well results;
- Maintaining strong cash margins per unit of production through cost management and proactive investment in production infrastructure;

- Improving the capital efficiency of our operations in terms of both well productivity and capital outlays, including supporting facilities;
- Maturing our asset base into a sustainable operating model for profitable reinvestment of cash flows for attractive, long-term returns on capital;
- Growing our inventory of well locations through delineation of emerging targets on our existing acreage positions and selective acquisitions of leasehold rights and mineral interests in areas complementary to our existing core operating areas; and
- Preserving a strong financial position, focusing on appropriate capital allocation decisions under various commodity pricing scenarios, prudent risk management and generating free cash flow to reduce leverage.

Our Strengths

We believe the following attributes position Callon to achieve its objectives:

- **Strong Foundation** - Reputation as a safe and responsible operator built over several decades in the oil and gas industry;
- **Quality Assets** - High quality Permian Basin asset base with several years of proven well results from multiple target zones that benefit from early investments in critical supporting infrastructure including sustainable investments in water recycling and a more mature asset base in the Eagle Ford Shale which has lower operational risk and generates predictable, repeatable well results;
- **Operational Control** - High degree of operational control that allows us to efficiently maximize value through long-term and daily decisions that drive our strategy;
- **Talented Workforce** - Seasoned employee base that has continued to benefit from the hiring of quality employees across various disciplines, as well as the integration of employees from the Carrizo Acquisition, that have been integrated into our unifying culture.

Oil and Natural Gas Properties

Summary of 2019 Proved Reserves, Production and Drilling by Region

	Permian Basin		Eagle Ford Shale		Total	
Proved reserves (1)						
Crude oil (MBbls)		237,413		108,948		346,361
Natural gas (MMcf)		656,594		100,540		757,134
NGLs (MBbls)		50,128		17,334		67,462
Total proved reserves (MBoe)		396,973		143,039		540,012
Proved reserves by classification (MBoe)						
Proved developed		164,503		66,474		230,977
Proved undeveloped		232,470		76,565		309,035
Total proved reserves (MBoe)		396,973		143,039		540,012
Percent of proved developed reserves		71%		29%		100%
Percent of proved undeveloped reserves		75%		25%		100%
Percent of total reserves		74%		26%		100%
Production volumes (1)(2)	**Total**	**Per Day** (2)	**Total**	**Per Day** (2)	**Total**	**Per Day** (2)
Crude oil (MBbls and Bbls/d)	11,365	31,136	300	821	11,665	31,957
Natural gas (MMcf and Mcf/d)	19,484	53,381	234	640	19,718	54,021
NGLs (MBbls and Bbls/d)	93	254	42	116	135	370
Total production volumes (MBoe and Boe/d)	14,705	40,287	381	1,044	15,086	41,331
Percent of total production		97%		3%		100%

	Permian Basin		Eagle Ford Shale		Total	
Operated Well Data	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Year Ended December 31, 2019						
Drilled (2)	61	53.7	2	2.0	63	55.7
Completed (2)	55	47.1	—	—	55	47.1
December 31, 2019						
Drilled but uncompleted	28	25.0	36	32.7	64	57.7
Producing	810	702.6	599	539.7	1,409	1,242.3

(1) The estimated proved reserves acquired in the Carrizo Acquisition and production associated with such reserves are presented on a three-stream basis and include NGLs, whereas, all other estimated proved reserve and production volumes are on a two-stream basis.
(2) Includes activity from the Carrizo Acquisition subsequent to the December 20, 2019 closing date.

Regional Overview

Permian Basin

As of December 31, 2019, we owned 173,922 gross (116,784 net) acres in the Permian Basin, all of which was located in the Midland and Delaware Basins. Average net production from our Permian Basin properties increased approximately 22% to 40,287 Boe/d in 2019 from 32,926 Boe/d in 2018. In the fourth quarter of 2019, we closed on the Carrizo Acquisition which added approximately 45,000 net acres in the Delaware Basin to our portfolio. We currently expect to direct the majority of our 2020 Capital Budget, as defined below, towards opportunities in the Permian Basin.

Eagle Ford Shale

We acquired our Eagle Ford properties, primarily located in LaSalle County and, to a lesser extent, in McMullen, Frio and Atascosa counties in Texas, through the Carrizo Acquisition. As of December 31, 2019, we held interests in approximately 90,560 gross (76,234 net) acres.

Proved Oil and Gas Reserves

The following table sets forth summary information with respect to our estimated proved reserves, standardized measure of discounted future net cash flows and PV-10 for the years ended December 31, 2019, 2018, and 2017. The estimated proved reserves obtained as a result of the Carrizo Acquisition were prepared by Ryder Scott Company, L.P. ("Ryder Scott"), the independent third party reserve engineers historically retained by Carrizo. All other estimated proved reserves for each respective year were prepared by DeGolyer and MacNaughton ("D&M"), Callon's independent third party reserve engineers (together with Ryder Scott, the "Reserve Engineering Firms"). For further information concerning D&M's and Ryder Scott's estimates of our proved reserves as of December 31, 2019, see the reserve reports included as exhibits to this 2019 Annual Report on Form 10-K. The prices used in the calculation of our estimated proved reserves and PV-10 were based on the average realized prices for sales of oil, natural gas liquids ("NGLs"), and natural gas on the first calendar day of each month during the year ("12-Month Average Realized Price") in accordance with SEC rules.

	As of December 31,		
	2019	**2018**	**2017**
Proved developed reserves [1]			
Crude oil (MBbls)	152,687	92,202	51,920
Natural gas (MMcf)	320,676	218,417	104,389
NGLs (MBbls)	24,844	—	—
Total proved developed reserves (MBoe)	230,977	128,605	69,318
Proved undeveloped reserves [1]			
Crude oil (MBbls)	193,674	87,895	55,152
Natural gas (MMcf)	436,458	132,049	75,021
NGLs (MBbls)	42,618	—	—
Total proved undeveloped reserves (MBoe)	309,035	109,903	67,656
Total proved reserves [1]			
Crude oil (MBbls)	346,361	180,097	107,072
Natural gas (MMcf)	757,134	350,466	179,410
NGLs (MBbls)	67,462	—	—
Total proved reserves (MBoe)	540,012	238,508	136,974
Proved developed reserves %	43%	54%	51%
Proved undeveloped reserves %	57%	46%	49%
Average realized prices			
Crude oil ($/Bbl)	$53.90	$58.40	$49.48
Natural gas ($/Mcf)	$1.55	$3.64	$3.47
NGLs ($/Bbl)	$15.58	—	—
Standardized measure of discounted future net cash flows (GAAP) (in millions)	$4,951.0	$2,941.3	$1,556.7
PV-10 (Non-GAAP):			
Proved developed PV-10	$3,246.8	$2,222.0	$1,030.3
Proved undeveloped PV-10	2,122.8	927.2	546.4
Total PV-10 (Non-GAAP)	$5,369.6	$3,149.2	$1,576.8

(1) The estimated proved reserves acquired in the Carrizo Acquisition are presented on a three-stream basis and include NGLs, whereas, all other estimated proved reserve volumes are on a two-stream basis.

Reconciliation of Standardized Measure of Discounted Future Net Cash Flows (GAAP) to PV-10 (Non-GAAP)

We believe that the presentation of PV-10 provides greater comparability when evaluating oil and gas companies due to the many factors unique to each individual company that impact the amount and timing of future income taxes. In addition, we believe that PV-10 is widely used by investors and analysts as a basis for comparing the relative size and value of our proved reserves to other oil and gas companies. PV-10 should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows or any other measure of a company's financial or operating performance presented in accordance with GAAP. The definition of PV-10 as defined in "Glossary of Certain Terms" may differ significantly from the definitions used by other companies to compute similar measures. As a result, PV-10 as defined may not be comparable to similar measures provided by other companies. A reconciliation of the standardized measure of discounted future net cash flows to PV-10 is presented below. Neither PV-10 nor the standardized measure of discounted future net cash flows purport to represent the fair value of our proved oil and gas reserves.

	As of December 31,		
	2019	2018	2017
		(In millions)	
Standardized measure of discounted future net cash flows (GAAP)	$4,951.0	$2,941.3	$1,556.7
Add: present value of future income taxes discounted at 10% per annum	418.6	207.9	20.1
PV-10 (Non-GAAP)	$5,369.6	$3,149.2	$1,576.8

Proved Reserves

As of December 31, 2019, our estimated proved reserves totaled 540.0 MMBoe, an increase of 126% from the prior year end, and included 346.4 MMBbls of oil, 757.1 Bcf of natural gas and 67.5 MMBbls of NGLs with a standardized measure of discounted future net cash flows of $5.0 billion [(1)]. Oil constituted approximately 64% of our total estimated proved reserves and approximately 66% of our total estimated proved developed reserves. We added 59.4 MMBoe of new reserves in extensions and discoveries through our development efforts in our operating areas, of which 17.1 MMBoe were proved developed at a cost of $226.3 million, where we drilled a total of 63 gross (55.7 net) wells. We purchased reserves in place of 326.8 MMBoe associated with the Carrizo Acquisition. Sales of reserves in place of 32.5 MMBoe primarily included 18.6 MMBoe of proved developed reserves and 8.5 MMBoe of PUD reserves associated with the Ranger Divestiture. See "Note 4 - Acquisitions and Divestitures" of the Notes to our Consolidated Financial Statements for further discussion of the Carrizo Acquisition and the Ranger Divestiture.

Our net revisions of previous estimates were primarily related to revisions of proved undeveloped reserves. We reduced our estimated proved reserves through total net revisions of 37.2 MMBoe due to the following factors:

- 21.7 MMBoe from the observed impact of well spacing tests on producing wells and the related impact on PUD reserve estimates as we advance larger scale development concepts across our multi-zone inventory;
- 9.8 MMBoe from the reclassifications of PUDs within our optimized development plans that were moved outside of the five-year development window. The primary driver of these changes in our previous development plan was the Carrizo Acquisition which afforded the opportunity to reallocate capital across the combined portfolio in an effort to increase capital efficiency and resulting cash flow generation; and
- 5.7 MMBoe from the adverse effect of pricing and other economic factors

The following table provides a summary of the changes in our proved reserves for the year ended December 31, 2019.

	Total (MBoe)
Proved reserves as of December 31, 2018	238,508
Extensions and discoveries	59,424
Revisions to previous estimates	(37,216)
Purchase of reserves in place [(1)]	326,838
Sales of reserves in place	(32,456)
Production	(15,086)
Proved reserves as of December 31, 2019	540,012

(1) The estimated proved reserves acquired in the Carrizo Acquisition are presented on a three-stream basis and include NGLs, whereas, all other estimated proved reserve volumes are on a two-stream basis.

Proved Undeveloped Reserves

Annually, we review our PUDs to ensure appropriate plans exist for development of this reserve category. PUD reserves are recorded only if we have plans to convert these reserves into PDPs within five years of the date they are first recorded. Our development plans include the allocation of capital to projects included within our 2020 Capital Budget, as defined below, and, in subsequent years, the allocation of capital within our long-range business plan to convert PUDs to PDPs within this five year period.

The Company had extensions and discoveries of 42.4 MMBoe for our PUDs that were due to additional offset locations associated with our drilling program. During 2019, we acquired 201.5 MMBoe of PUD locations associated with the Carrizo Acquisition and had sales of reserves in place of 11.2 MMBoe of PUDs which was primarily a result of the Ranger Divestiture.

We had net revisions of 23.0 MMBoe to PUDs in 2019. These revisions reflect the impact of well spacing tests on certain PUD estimates and reclassifications of certain PUDs within our optimized development plans that were moved outside of the five-year development window as well as the adverse effect of pricing and other economic factors. The primary driver of the changes in our previous development plan was the Carrizo Acquisition which afforded the opportunity to reallocate capital across the combined portfolio in an effort to increase capital efficiency and resulting cash flow generation.

During 2019, we converted 11.0 MMBoe of PUDs that were booked as PUDs as of December 31, 2018 to proved developed at a total cost of $103.9 million, or $9.45 per Boe. We converted an additional 2.5 MMBoe of PUDs that were booked as PUDs during 2019 to proved developed at a total cost of $28.6 million, or $11.44 per Boe. Although our PUD conversion was below 20% for 2019, we currently estimate that we will convert approximately 50% of our PUDs as of December 31, 2019 in 2020 and 2021.

During 2019, we also incurred $15.9 million on PUDs that were drilled but uncompleted as of December 31, 2019. As of December 31, 2019, we had 32.2 MMBoe of PUDs associated with drilled but uncompleted wells, of which 29.3 MMBoe were associated with the Carrizo Acquisition. All of the reserves associated with drilled but uncompleted wells are scheduled to be completed in 2020. We expect to incur approximately $203.0 million of capital expenditures to complete these wells.

At December 31, 2019, we did not have any reserves that have remained undeveloped for five or more years since the date of their initial booking and all PUD locations are scheduled to be developed within five years of their initial booking.

Qualifications of Technical Persons

In accordance with the Standards Pertaining to Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers, D&M prepared approximately 40% of our estimates of proved reserves as of December 31, 2019 and 100% of our proved reserves as of December 31, 2018 and 2017. Ryder Scott prepared the estimates of proved reserves associated with the Carrizo Acquisition, which comprised approximately 60% of our proved reserves as of December 31, 2019. The technical persons responsible for preparing the reserves estimates meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Neither D&M nor Ryder Scott owns an interest in our properties and neither is employed on a contingent fee basis.

Our internal reserve engineer has over 20 years of experience in the petroleum industry and extensive experience in the estimation of reserves and the review of reserve reports prepared by third party engineering firms. Compliance as it relates to reporting the Company's reserves is the responsibility of our Chief Operating Officer, who is also our principal engineer. He has over 30 years of operations and industry experience and holds B.S. and Ph.D. degrees in Petroleum Engineering, in addition to a M.S. in Environmental and Planning Engineering, and is experienced in asset evaluation and management.

Internal Controls Over Reserve Estimation Process

The primary inputs to the reserve estimation process are comprised of technical information, financial data, production data, and ownership interest. All field and reservoir technical information is assessed for validity when the internal reserve engineer holds technical meetings with our geoscientists, operations, and land personnel to discuss field performance and to validate future development plans. The other inputs used in the reserve estimation process, including, but not limited to, future capital expenditures, commodity price differentials, production costs, and ownership percentages are subject to internal controls over financial reporting and are assessed for effectiveness annually.

To further enhance the control environment over the reserve estimation process, our Strategic Planning and Reserves Committee, an independent committee of the Company's board of directors (the "Board of Directors"), assists management and the Board of Directors with its oversight of the integrity of the determination of our oil and natural gas reserves and the work of the Reserve Engineering Firms. The Strategic Planning and Reserves Committee's charter also specifies that it shall perform, in consultation with the Company's management and senior reserves and reservoir engineering personnel, the following responsibilities:

- Oversee the appointment, qualification, independence, compensation and retention of the Reserve Engineering Firms engaged by the Company (including resolution of material disagreements between management and the Reserve Engineering Firms regarding reserve determination) for the purpose of preparing or issuing an annual reserve report. The Strategic Planning and

Reserves Committee shall review any proposed changes in the appointment of the Reserve Engineering Firms, determine the reasons for such proposal, and whether there have been any disputes between the Reserve Engineering Firms and management.

- Review the Company’s significant reserves engineering principles and any material changes thereto, and any proposed changes in reserves engineering standards and principles which have, or may have, a material impact on the Company’s reserves disclosure.
- Review with management and the Reserve Engineering Firms the proved reserves of the Company, and, if appropriate, the probable reserves, possible reserves and the total reserves of the Company, including: (i) reviewing significant changes from prior period reports; (ii) reviewing key assumptions used or relied upon by the Reserve Engineering Firms; (iii) evaluating the quality of the reserve estimates prepared by both the Reserve Engineering Firms and the Company relative to the Company’s peers in the industry; and (iv) reviewing any material reserves adjustments and significant differences between the Company’s and Reserve Engineering Firms’ estimates.
- If the Strategic Planning and Reserves Committee deems it necessary, it shall meet in executive session with the Reserve Engineering Firms to discuss the oil and gas reserve determination process and related public disclosures, and any other matters of concern in respect of the evaluation of the reserves.

During our last fiscal year, we filed no reports with other federal agencies which contain an estimate of proved reserves.

See “Item 8. Financial Statements and Supplementary Data - Supplemental Information on Oil and Natural Gas Operations” for additional information regarding our estimated proved reserves and the present value of estimated future net revenues from these proved reserves.

Capital Budget

Our Board approved operational capital expenditure budget for 2020 has been established at $975.0 million (the “2020 Capital Budget”), which includes running an average of eight to nine drilling rigs and an average of three completion crews. Approximately 10-15% of the 2020 Capital Budget is comprised of infrastructure and facilities capital. As part of our 2020 operated horizontal drilling program, we expect to drill approximately 165 gross operated wells and complete approximately 160 gross operated wells.

Our revenues, earnings, liquidity and ability to grow are substantially dependent on the prices we receive for, and our ability to develop, our reserves of oil and natural gas. We believe the long-term outlook for our business is favorable due to our resource base, low cost structure, financial strength, risk management, and disciplined investment of capital. We monitor current and expected market conditions, including the commodity price environment, and our liquidity needs and may adjust our capital investment plan accordingly.

Drilling Activity

The following table sets forth our operated and non-operated drilling activity for the years ended December 31, 2019, 2018 and 2017. In the table, “gross” refers to the total wells in which we have a working interest and “net” refers to gross wells multiplied by our working interest therein. As defined by the SEC, the number of wells drilled refers to the number of wells completed at any time during the respective year, regardless of when drilling was initiated. For definitions of exploratory wells, development wells, productive wells, and non-productive wells, see “—Glossary of Certain Terms”.

	Years Ended December 31,					
	2019 (1)		2018		2017	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells - Productive	56	36.7	55	44.7	33	26.5
Exploratory Wells - Non-productive	—	—	—	—	1	1.0
Development Wells - Productive	15	11.6	15	12.8	15	10.7
Development Wells - Non-productive	—	—	—	—	—	—

(1) Includes activity from the Carrizo Acquisition subsequent to the December 20, 2019 closing date.

Productive Wells

The following table sets forth the number of productive crude oil and natural gas wells in which we owned an interest as of December 31, 2019.

	Crude Oil		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Permian Basin - Operated	727	631.0	90	78.1	817	709.1
Permian Basin - Non-operated	119	13.1	63	3.0	182	16.1
Total Permian Basin	846	644.1	153	81.1	999	725.2
Eagle Ford Shale - Operated	609	548.0	2	1.8	611	549.8
Eagle Ford Shale - Non-operated	15	1.3	23	3.5	38	4.8
Total Eagle Ford Shale	624	549.3	25	5.3	649	554.6
Total	1,470	1,193.4	178	86.4	1,648	1,279.8

Production Volumes, Average Sales Prices and Operating Costs

The following tables set forth certain information regarding the production volumes and average sales prices received for, and average production costs associated with, the Company's sale of oil and natural gas for the periods indicated.

	Years Ended December 31,		
	2019 (1)	2018	2017
Total production (2)			
Oil (MBbls)	11,665	9,443	6,557
Natural gas (MMcf)	19,718	15,447	10,896
NGLs (MBbls)	135	—	—
Total barrels of oil equivalent (MBoe)	15,086	12,018	8,373
Daily production volumes by product (2)			
Oil (Bbls/d)	31,957	25,871	17,964
Natural gas (Mcf/d)	54,021	42,321	29,852
NGLs (Bbls/d)	370	—	—
Total barrels of oil equivalent (Boe/d)	41,331	32,926	22,940
Daily production volumes by region (2)			
Permian Basin	40,287	32,926	22,940
Eagle Ford Shale	1,044	—	—
Total barrels of oil equivalent (Boe/d)	41,331	32,926	22,940

	Years Ended December 31,		
	2019 (1)	2018	2017
Revenues (in thousands)			
Oil	$633,107	$530,898	$322,374
Natural gas	36,390	56,726	44,100
NGLs	2,075	—	—
Total revenues	$671,572	$587,624	$366,474
Operating costs (in thousands)			
Lease operating expense	$91,827	$69,180	$49,907
Production taxes	42,651	35,755	22,396
Total operating costs	$134,478	$104,935	$72,303
Average realized sales price (excluding impact of settled derivatives)			
Oil (per Bbl)	$54.27	$56.22	$49.16
Natural gas (per Mcf)	1.85	3.67	4.05
NGL (per Bbl)	15.37	—	—
Total (per Boe)	$44.52	$48.90	$43.77
Average realized sales price (including impact of settled derivatives)			
Oil (per Bbl)	$53.31	$53.31	$47.78
Natural gas (per Mcf)	2.22	3.69	4.10
NGL (per Bbl)	15.37	—	—
Total (per Boe)	$44.27	$46.63	$42.76
Operating costs per Boe			
Lease operating expense	$6.09	$5.76	$5.96
Production taxes	2.83	2.98	2.67
Total (per Boe)	$8.92	$8.74	$8.63

(1) Includes activity from the Carrizo Acquisition subsequent to the December 20, 2019 closing date.

(2) The production associated with reserves acquired in the Carrizo Acquisition is presented on a three-stream basis and include NGLs, whereas, all other production volumes are on a two-stream basis.

Major Customers

Our production is sold generally on month-to-month contracts at prevailing market prices. The following table presents customers that represented 10% or more of our total revenues for at least one of the periods presented:

	Years Ended December 31,		
	2019	2018	2017
Rio Energy International, Inc.	26%	28%	17%
Enterprise Crude Oil, LLC	19%	14%	18%
Plains Marketing, L.P.	15%	21%	29%
Shell Trading Company	10%	*	*

* - Less than 10% for the respective year.

Because alternative purchasers of oil and natural gas are readily available, we believe that the loss of any of these purchasers would not result in a material adverse effect on our ability to sell future oil and natural gas production. In order to mitigate potential exposure to credit risk, we may require from time to time for our customers to provide financial security.

Leasehold Acreage

The following table shows our approximate developed and undeveloped leasehold acreage as of December 31, 2019. Developed acreage refers to acreage on which wells have been completed to a point that would permit production of oil and gas in commercial quantities. Undeveloped acreage refers to acreage on which wells have not been drilled or completed to a point that would permit production of oil and gas in commercial quantities whether or not the acreage contains proved reserves.

	Developed Acreage		Undeveloped Acreage		Total Acreage		Net Undeveloped Acreage Expiring		
	Gross	Net	Gross	Net	Gross	Net	2020	2021	2022
Permian Basin (1)	137,786	97,352	36,136	19,432	173,922	116,784	13,765	1,903	981
Eagle Ford Shale (2)	75,864	64,146	14,696	12,088	90,560	76,234	1,357	—	300
Other (3)	2,123	174	79,615	57,070	81,738	57,244	—	1,234	48,504
Total	215,773	161,672	130,447	88,590	346,220	250,262	15,122	3,137	49,785

(1) Approximately 16%, 81% and 39% of the acreage expiring in 2020, 2021 and 2022, respectively, will be developed prior to expiration or extended by lease extension payments. The acreage expiring in 2020 is primarily in our Alpine High area, which was acquired as part of the Carrizo Acquisition, where, along with the other remaining acreage, we have no current development plans.

(2) Approximately 87% and 100% of the acreage expiring in 2020 and 2022, respectively, will be developed prior to expiration or extended by lease extension payments. We have no current development plans for the remaining expiring acreage as of December 31, 2019.

(3) Other includes non-core acreage principally located in Texas. We have no current development plans with this acreage as of December 31, 2019.

Our lease agreements generally terminate if producing wells have not been drilled on the acreage within their primary term or an extension thereof (a period that can be from three to five years depending on the area). The percentage of net undeveloped acreage expiring in 2020, 2021 and 2022 assumes that no producing wells have been drilled on acreage within their primary term or have been extended. We manage our lease expirations to ensure that we do not experience unintended material expirations. Our leasehold management efforts include scheduling drilling in order to hold leases by production or timely exercising our contractual rights to extend the terms of leases by continuous operations or the payment of lease extension payments and delay rentals. We may choose to allow some leases to expire that are no longer part of our development plans.

The proved undeveloped reserves associated with acreage expiring over the next three years are not material to the Company.

Other

Industry Segment and Geographic Information

For segment reporting purposes, the Company considers all of the current development and operating areas to be one reportable segment: the development and production of oil and natural gas. All of the Company's assets are located within the United States and all operations are located within Texas. All of the production revenues generated from operations are contracted and sold to customers located in the United States.

Title to Properties

The Company believes that the title to its oil and natural gas properties is good and defensible in accordance with standards generally accepted in the oil and gas industry, subject to such exceptions which, in our opinion, are not so material as to detract substantially from the use or value of such properties. The Company's properties are potentially subject to one or more of the following:

- royalties and other burdens and obligations, express or implied, under oil and natural gas leases;
- overriding royalties and other burdens created by us or our predecessors in title;
- a variety of contractual obligations (including, in some cases, development obligations) arising under operating agreements; farm-out agreements, production sales contracts and other agreements that may affect the properties or their titles;
- back-ins and reversionary interests existing under purchase agreements and leasehold assignments;
- liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing obligations to unpaid suppliers and contractors and contractual liens under operating agreements;
- pooling, unitization and communitization agreements, declarations and orders; and
- easements, restrictions, rights-of-way and other matters that commonly affect property.

To the extent that such burdens and obligations affect the Company's rights to production revenues, these characteristics have been taken into account in calculating Callon's net revenue interests and in estimating the size and value of its reserves. The Company believes that the burdens and obligations affecting our properties are typical within the industry for properties of the kind owned by Callon.

Seasonality of Business

Weather conditions and seasonality affect the demand for and prices of, oil and natural gas. Due to these fluctuations, results of operations for quarterly interim periods may not be indicative of the results realized on an annual basis.

Competition

The Company operates in the oil and natural gas industry, which is highly competitive. The Company's business experiences strong competition from a number of parties that may range from small independent producers to major integrated companies. Competition affects the Company's ability to acquire additional properties and resources necessary to develop assets. In higher commodity pricing environments, competition also exists in the form of contracting for drilling, pumping, and workover equipment, and securing skilled personnel to both develop and operate existing assets. Many of the competitors mentioned above may be able to pay for more sought-after properties or access equipment, infrastructure, or personnel. The industry also experiences, from time to time, shortages in resources such as the availability of drilling and workover rigs, other equipment, pipes and materials, infrastructures, and skilled personnel, all of which can delay development, exploration, and workover activities as well as result in significant cost increases.

Insurance

In accordance with industry practice, the Company maintains insurance against some, but not all, of the operating risks to which its business is exposed. While not all inclusive, the Company's insurance policies generally protect against bodily injury and property damage, pollution and other environmental damages, employee benefits, employee injury and control of well insurance for its exploration and production operations.

The Company enters into master service agreements with its third-party contractors, including hydraulic fracturing contractors, in which they agree to indemnify the Company for injuries and deaths of the service provider's employees, as well as contractors and subcontractors hired by the service provider. Similarly, the Company generally agrees to indemnify each third-party contractor against claims made by employees of the Company and the Company's other contractors. Additionally, each party generally is responsible for damage to its own property. The Company re-evaluates the purchase of insurance, coverage limits and deductibles annually. Future insurance coverage for the oil and natural gas industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that are economically acceptable. While based on the Company's risk analysis we believe that we are properly insured, no assurance can be given that the Company will be able to maintain insurance in the future at rates that it considers reasonable. In such circumstances, the Company may elect to self-insure or maintain only catastrophic coverage for certain risks in the future.

Corporate Offices

The Company's headquarters are located in Houston, Texas, in a building with office space leased by the Company. We own office buildings in Natchez, Mississippi and Dilley and Pecos, Texas and lease and own offices in the Midland, Texas area. Because alternative locations to our leased spaces are readily available, the replacement of any of our leased offices would not result in material expenditures**.**

Employees

With the addition of employees from the Carrizo Acquisition that closed on December 20, 2019, Callon had 475 employees as of December 31, 2019. None of the Company's employees are currently represented by a union, and the Company believes that it has good relations with its employees.

Regulations

General. Oil and natural gas operations such as ours are subject to various types of legislation, regulation and other legal requirements enacted by governmental authorities. Legislation and regulation affecting the entire oil and natural gas industry is continuously being reviewed for potential revision. Some of these requirements carry substantial penalties for failure to comply.

Exploration and Production. Our operations are subject to federal, state and local regulations that include requirements for permits to drill and to conduct other operations and for provision of financial assurances (such as bonds and letters of credit) covering drilling and well operations. Other activities subject to regulation are:

- the location and spacing of wells;
- the method of drilling and completing and operating wells;
- the rate and method of production;
- the surface use and restoration of properties upon which wells are drilled and other exploration activities;
- notice to surface owners and other third parties;
- the venting or flaring of natural gas;
- the plugging and abandoning of wells;
- the discharge of contaminants into water and the emission of contaminants into air;
- the disposal of fluids used or other wastes obtained in connection with operations;
- the marketing, transportation and reporting of production; and
- the valuation and payment of royalties.

Our sales of oil and natural gas are affected by the availability, terms and cost of pipeline transportation. The price and terms for access to pipeline transportation remain subject to extensive federal and state regulation. If these regulations change, we could face higher transmission costs for our production and, possibly, reduced access to transmission capacity.

Various proposals and proceedings that might affect the petroleum industry are pending before Congress, federal administrative agencies such as the Federal Energy Regulatory Commission ("FERC"), various state and administrative agencies and legislatures, and the courts. Historically, the industry has been heavily regulated and we can offer you no assurance that the less stringent regulatory approach recently pursued by the FERC and state administrative agencies and Congress will continue nor can we predict what effect such proposals or proceedings may have on our operations.

We do not currently anticipate that compliance with existing laws and regulations governing exploration and production will have a significantly adverse effect upon our capital expenditures, earnings or competitive position.

Environmental Matters and Regulation. Our oil and natural gas exploration, development and production operations are subject to stringent laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous federal, state and local governmental agencies, such as the U.S. Environmental Protection Agency (the "EPA"), issue regulations which often require difficult and costly compliance measures. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically sensitive and other protected areas, require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing pits, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from our operations or relating to our owned or operated facilities. Violations of environmental laws could result in administrative, civil or criminal fines and injunctive relief. The strict and joint and several liability nature of certain such laws and regulations could impose liability upon us regardless of fault. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons, air emissions or other waste products into the environment. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly pollution control or waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as the oil and natural gas industry in general. In recent years, the oil and natural gas exploration and production industry has been the subject of increasing scrutiny and regulation by environmental authorities. Our management believes that we are in substantial compliance with applicable environmental laws and regulations and we have not experienced any material adverse effect from compliance with these environmental requirements. Although such laws and regulations can increase the cost of planning, designing, installing and operating our facilities, it is anticipated that, absent the occurrence of an extraordinary event, compliance with them will not have a material effect upon our operations, capital expenditures, earnings or competitive position in the marketplace.

Waste Handling. The Resource Conservation and Recovery Act ("RCRA"), as amended, and comparable state statutes and regulations promulgated thereunder, affect oil and natural gas exploration, development and production activities by imposing requirements regarding the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. With federal approval, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Although most wastes associated with the exploration, development and production of oil and natural gas are exempt from regulation as hazardous wastes under RCRA and its state analogs, it is possible that some wastes we generate presently or in the future may be subject to regulation under RCRA and state analogs. Additionally, we cannot assure you that the EPA or state or local governments will not adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and natural gas exploration, development and production wastes as "hazardous wastes." Additionally, following the filing of a lawsuit in the U.S. District Court for the District of Columbia in May 2016 by several non-governmental environmental groups against the EPA for the agency's failure to timely assess its RCRA Subtitle D criteria regulations for oil and gas wastes, the EPA and the environmental groups entered into an agreement that was finalized in a consent decree issued by the District Court on December 28, 2016. Under the decree, the EPA was required to propose no later than March 15, 2019, a rulemaking for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or sign a determination that revision of the regulations was not necessary. On April 23, 2019, the EPA determined that a revision of the regulations was not necessary. If the EPA proposes a rulemaking for revised oil and gas waste regulations in the future, any such changes in the laws and regulations could have a material adverse effect on our capital expenditures and operating expenses.

Administrative, civil and criminal penalties can be imposed for failure to comply with waste handling requirements. We believe that we are in substantial compliance with applicable requirements related to waste handling, and that we hold all necessary and up-to-date permits, registrations and other authorizations to the extent that our operations require them under such laws and regulations. Although we do not believe the current costs of managing our wastes, as presently classified, to be significant, any legislative or regulatory reclassification of wastes associated with oil and natural gas exploration and production could increase our costs to manage and dispose of such wastes.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), imposes joint and several liability for costs of investigation and remediation and for natural resource damages without regard to fault or legality of the original conduct, on certain classes of persons with respect to the release into the environment of substances designated under CERCLA as hazardous substances. These classes of persons, or potentially responsible parties ("PRPs") include the current and past owners or operators of a site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance found at the site. CERCLA also authorizes the EPA and, in some instances, third parties to take actions in response to threats to public health or the environment and to seek to recover from the PRPs the costs of such action. Many states have adopted comparable or more stringent state statutes.

Although CERCLA generally exempts "petroleum" from the definition of hazardous substance, in the course of our operations, we have generated and will generate wastes that may fall within CERCLA's definition of hazardous substance and may have disposed of these wastes at disposal sites owned and operated by others. Comparable state statutes may not provide a comparable exemption for petroleum. We may also be the owner or operator of sites on which hazardous substances have been released. To our knowledge, neither we nor our predecessors have been designated as a PRP by the EPA under CERCLA; we also do not know of any prior owners or operators of our properties that are named as PRPs related to their ownership or operation of such properties. In the event contamination is discovered at a site on which we are or have been an owner or operator or to which we sent hazardous substances, we could be liable for the costs of investigation and remediation and natural resources damages.

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 we have utilized operating, waste disposal, and water 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 offsite locations, where such substances have been taken for disposal. In addition, some of these properties have been operated by third parties or by previous owners or operators whose 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. In the future, we could be required to remediate property, including groundwater, containing or impacted by previously disposed wastes (including wastes disposed or released by prior owners or operators, or property contamination or groundwater contamination by prior owners or operators) or to perform remedial plugging operations to prevent future or mitigate existing contamination.

Water Discharges. The Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act, the Safe Drinking Water Act, the Oil Pollution Act ("OPA"), and analogous state laws and regulations promulgated thereunder impose restrictions and strict controls regarding the unauthorized discharge of pollutants, including produced waters and other gas and oil wastes, into navigable waters of the United States (a term broadly defined to include, among other things, certain wetlands), as well as state waters for analogous state programs. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or applicable state analog. The Clean Water Act and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit from the U.S. Army Corps of Engineers. The EPA issued a final rule on the federal jurisdictional reach over waters of the United States in 2015, which was repealed by the EPA on October 22, 2019. On January 23, 2020, the EPA and the U.S. Army Corps of Engineers issued a final rule re-defining the term "waters of the United States" as applied under the Clean Water Act and narrowing the scope of waters subject to federal regulation. The rule is the subject of various legal challenges, creating uncertainty regarding federal jurisdiction over waters of the United States.

The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions.

The Oil Pollution Act is the primary federal law for oil spill liability. The OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must develop and maintain facility response contingency plans and maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters.

Noncompliance with the Clean Water Act or the OPA may result in substantial administrative, civil and criminal penalties, as well as injunctive obligations. We believe we are in material compliance with the requirements of each of these laws.

Air Emissions. The federal Clean Air Act, as amended, and comparable state and local laws and regulations, regulate emissions of various air pollutants through the issuance of permits and the imposition of other requirements. The EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. New facilities may be required to obtain permits before work can begin, and modified and existing facilities may be required to obtain additional permits. As a result, we may need to incur capital costs in order to remain in compliance. Obtaining or renewing permits also has the potential to delay the development of oil and natural gas projects. Federal and state regulatory agencies can impose administrative, civil and criminal penalties and seek injunctive relief for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. We believe that we are in substantial compliance with all applicable air emissions regulations and that we hold all necessary and valid construction and operating permits for our operations.

On June 3, 2016, the EPA expanded its regulatory coverage in the oil and natural gas industry with additional regulated equipment categories, and the addition of new rules limiting methane emissions from new or modified sites and equipment. Although the EPA attempted to suspend enforcement of the methane rule, this action was ruled improper by the U.S. Court of Appeals for the D.C. Circuit on July 2, 2017. Subsequently, in September 2018, the EPA issued a proposed rulemaking that could substantially change the obligations associated with methane emissions, limiting obligations for the oil and natural gas industry. Separately, in August 2019, the EPA issued proposed amendments that would that would rescind requirements related to the regulation of methane emissions from the oil and natural gas industry. Neither rulemaking has been finalized and, therefore, future obligations continue to remain uncertain under the Clean Air Act.

Climate Change. Numerous reports from scientific and governmental bodies such as the United Nations Intergovernmental Panel on Climate Change have expressed heightened concerns about the impacts of human activity, especially fossil fuel combustion, on the global climate. In turn, governments and civil society are increasingly focused on limiting the emissions of GHGs, including emissions of carbon dioxide from the use of oil and natural gas.

In December 2015, the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change resulted in 195 countries, including the United States, coming together to develop the so-called “Paris Agreement,” which calls for the parties to undertake “ambitious efforts” to limit the average global temperature. The Agreement went into effect on November 4, 2016, and establishes a framework for the parties to cooperate and report actions to reduce GHG emissions. The United States formally announced its intent to withdraw from the Paris Agreement on November 4, 2019, which withdrawal will become effective on November 4, 2020. Certain U.S. city and state governments have announced their intention to satisfy their proportionate obligations under the Paris Agreement. In addition, legislation has from time to time been introduced in Congress that would establish measures restricting GHG emissions in the United States, and a number of states have begun taking actions to control and/or reduce emissions of GHGs.

Any legislation or regulatory programs at the federal, state, or city levels designed to reduce GHG emissions could 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. Moreover, incentives to conserve energy or use alternative energy sources, such as policies designed to increase utilization of zero-emissions or electric vehicles, as a means of addressing climate change could reduce demand for the oil and natural gas we produce.

In the absence of comprehensive federal legislation on GHG emission control, the EPA attempted to require the permitting of GHG emissions. Although the Supreme Court struck down the permitting requirements, it upheld the EPA’s authority to control GHG emissions when a permit is required due to emissions of other pollutants.

The EPA has established GHG reporting requirements for certain sources in the petroleum and natural gas industry, requiring those sources to monitor, maintain records on, and annually report their GHG emissions. Although these requirements do not limit the amount of GHGs that can be emitted, they do require us to incur costs to monitor, keep records of, and report GHG emissions associated with our operations.

Parties concerned about the potential effects of climate change have also directed their attention at sources of financing for energy companies, which has resulted in certain financial institutions, funds and other capital providers restricting or eliminating their investment in oil and natural gas activities. In addition, some parties have initiated public nuisance claims under federal or state common law against certain companies involved in the production of oil and natural gas. Although our business is not a party to any such litigation, we could be named in actions making similar allegations, which could lead to costs and materially impact our financial condition in an adverse way.

Finally, most scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce significant physical effects, such as increased frequency and severity of droughts, storms, floods and other climatic events. If any such effects were to occur, they could adversely affect or delay demand for the oil or natural gas produced or cause us to incur significant costs in preparing for or responding to the effects of climatic events themselves. Potential adverse effects could include disruption of our production activities, including, for example, damages to our facilities from winds or floods or increases in our costs of operation or reductions in the efficiency of our operations, as well as potentially increased costs for insurance coverages in the aftermath of such effects.

Regulation of Hydraulic Fracturing. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations, including shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The federal Safe Drinking Water Act ("SDWA") regulates the underground injection of substances through the Underground Injection Control ("UIC") program. Hydraulic fracturing is generally exempt from regulation under the UIC program, and the hydraulic fracturing process is typically regulated by state oil and gas commissions and not at the federal level, as the SDWA expressly excludes regulation of these fracturing activities (except where diesel is a component of the fracturing fluid, as further discussed below). Legislation to amend the SDWA to repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing has been proposed in past legislative sessions but has not passed.

The EPA, however, issued guidance on permitting hydraulic fracturing that uses fluids containing diesel fuel under the UIC program, specifically as "Class II" UIC wells. In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources "under some circumstances," including 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. This report could result in additional regulatory scrutiny that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and business. Further, on June 28, 2016, the EPA published an effluent limit guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants.

On June 3, 2016, the EPA adopted regulations under the federal Clean Air Act that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package included New Source Performance Standards ("NSPS") for hydraulically fractured natural gas and oil wells to address emissions of sulfur dioxide, volatile organic compounds ("VOCs") and methane, with a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The final rule sought to achieve a 95% reduction in VOCs and methane emitted by requiring the use of reduced emission completions or "green completions" on all hydraulically-fractured gas and newly constructed or refractured oil wells. The rules also established specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. Notably, on October 15, 2018, the EPA published a proposed rule that would make a series of revisions to the 2016 NSPS; these revisions have yet to be finalized. Separately, on August 28, 2019, the EPA published a proposed rule that would that would rescind requirements related to the regulation of methane emissions from the oil and gas industry; these revisions have yet to be finalized.

On March 20, 2015, the U.S. Bureau of Land Management (the "BLM") finalized a rule regulating hydraulic fracturing activities on federal lands, including requirements for disclosure, wellbore integrity and handling of flowback water; however, on December 29, 2017, the BLM issued a rescission of the hydraulic fracturing rule. This rescission and the rule as promulgated are subject to ongoing litigation. Additionally, on November 18, 2016, the BLM finalized limitations on methane emissions from venting and flaring and leaking equipment from oil and natural gas activities on public lands, but on September 28, 2018 issued a final rule repealing certain provisions of the 2016 rule and reinstating the pre-2016 regulations; a lawsuit challenging the September 2018 rule revision is pending.

Several states, including Texas, and some municipalities, have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances and/or require the disclosure of the composition of hydraulic fracturing fluids. For example, Texas law requires that the well operator disclose the list of chemical ingredients subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") for disclosure on a website and also file the list of chemicals with the Texas Railroad

Commission (the "RRC") with the well completion report. The total volume of water used to hydraulically fracture a well must also be disclosed to the public and filed with the RRC.

Additionally, some states, localities and local regulatory districts have adopted or have considered adopting regulations to limit, and in some cases impose a moratorium on, hydraulic fracturing or other restrictions on drilling and completion operations, including requirements regarding casing and cementing of wells; testing of nearby water wells; or restrictions on access to, and usage of, water. Further, there has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, impacts on drinking water supplies, use of water and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated across the U.S. implicating hydraulic fracturing practices. 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 as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations of harm. In addition, if hydraulic fracturing is further regulated at the federal or state level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of potential federal or state legislation governing hydraulic fracturing. In light of concerns about seismic activity being triggered by the injection of produced waters into underground wells, certain regulators are also considering additional requirements related to seismic safety for hydraulic fracturing activities. A 2015 U.S. Geological Survey report identified eight states with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and gas extraction. Any regulation that restricts our ability to dispose of produced waters or increases the cost of doing business could cause curtailed or decreased demand for our services and have a material adverse effect on our business.

Surface Damage Statutes ("SDAs"). In addition, a number of states and some tribal nations have enacted SDAs. These laws are designed to compensate for damage caused by oil and gas development operations. Most SDAs contain entry notification and negotiation requirements to facilitate contact between operators and surface owners/users. Most also contain binding requirements for payments by the operator to surface owners/users in connection with exploration and operating activities in addition to bonding requirements to compensate for damages to the surface as a result of such activities. Costs and delays associated with SDAs could impair operational effectiveness and increase development costs.

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal lands may be subject to the National Environmental Policy Act ("NEPA"), which 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. Recent litigation by environmental non-governmental organizations has alleged that the Environmental Assessments for certain oil and natural gas projects violated NEPA by failing to account for climate change and the greenhouse gas emissions impacts of such projects. On January 10, 2020, the Council on Environmental Quality issued a proposed rule designed to streamline approvals for projects under NEPA. Among other revisions, the proposed rule would redefine environmental "effects" or "impacts" as the effects "that are reasonably foreseeable and have a reasonably close causal relationship to the proposed action or alternatives." The proposed rule would also eliminate the current "direct," "indirect," or "cumulative" categories of effects. This rulemaking process is ongoing. To the extent that 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 impose additional conditions upon the development of oil and natural gas projects.

Endangered Species Act. The Endangered Species Act ("ESA") was established to protect endangered and threatened species. Pursuant to that act, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' or its habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The U.S. Fish and Wildlife Service must also designate the species' critical habitat and suitable habitat as part of the effort to ensure survival of the species. A final rule amending how critical habitat and suitable habitat areas are designated under the ESA was finalized by the U.S. Fish and Wildlife Service in 2016. A critical habitat or suitable habitat designation could result in further material restrictions to land use and may materially delay or prohibit land access for oil and natural gas development. If the Company was to have a portion of its leases designated as critical or suitable habitat or a protected species were located on a lease, it may adversely impact the value of the affected leases.

Other Regulation of the Oil and Natural Gas Industry. The oil and natural gas industry is extensively regulated by numerous federal, state and local agencies and authorities. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations that are binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other similar companies in the industry with similar types, quantities and locations of production.

The availability, terms and cost of transportation significantly affect sales of oil and natural gas. The interstate transportation of oil and natural gas is subject to federal regulation, by the FERC which regulates the terms, conditions and rates for interstate transportation and storage service and various other matters. State regulations govern the rates, terms, and conditions of service associated with access to interstate oil and natural gas pipeline transportation. FERC's regulations for interstate oil and natural gas transportation in some circumstances may also affect the intrastate transportation of oil and natural gas.

Although oil and natural gas sales prices are currently unregulated, the federal government historically has been active in the area of oil and natural gas sales regulation. We cannot predict whether new legislation to regulate oil and natural gas sales might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on our operations. Sales of natural gas, condensate, oil and natural gas liquids are not currently regulated and are made at market prices.

Exports of US Oil Production and Natural Gas Production. In December 2015, the federal government ended its decades-old prohibition of exports of oil produced in the lower 48 states of the US. As a result, exports of U.S. oil have increased significantly, reinforcing the general perception in the industry that the end of the U.S. export ban was positive for producers of U.S. oil. In addition, the U.S. Department of Energy authorizes exports of natural gas, including exports of natural gas by pipelines connecting U.S. natural gas production to pipelines in Mexico, and the export of liquefied natural gas ("LNG") through LNG export facilities, the construction and operation of which are regulated by FERC. Since 2016, natural gas produced in the lower 48 states of the U.S. has been exported as LNG from export facilities in the U.S. Gulf Coast region. LNG export capacity has steadily increased in recent years, and is expected to continue increasing due to numerous export facilities that are currently being developed. The industry generally believes that this sustained growth in exports will be a positive development for producers of U.S. natural gas.

Drilling and Production. Our operations are subject to various types of regulation at the federal, state and local level. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. The state, and some counties and municipalities, in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the timing of construction or drilling activities, including seasonal wildlife closures;
- the rates of production or "allowables";
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to, and consultation with, surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. 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. States do not regulate wellhead prices or engage in other similar direct regulation, but we cannot assure you that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and natural gas that may be produced from our wells, negatively affecting the economics of production from these wells or to limit the number of locations we can drill.

Federal, state and local regulations provide detailed requirements for the abandonment of wells, closure or decommissioning of production facilities and pipelines and for site restoration in areas where we operate. The U.S. Army Corps of Engineers and many other state and local authorities also have regulations for plugging and abandonment, decommissioning and site restoration. Some state agencies and municipalities require bonds or other financial assurances to support those obligations.

Natural Gas Sales and Transportation. Historically, federal legislation and regulatory controls have affected the price of the natural gas we produce and the manner in which we market our production and have it transported. FERC has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 ("NGA") and the Natural Gas Policy Act of 1978 ("NGPA"). Since 1978, various federal laws have been enacted which have resulted in the complete removal of all price and non-price controls for "first sales," which include all of our sales of our own production.

Under the Energy Policy Act of 2005 ("EPAct") Congress amended the NGA and NGPA to give FERC substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess civil penalties up to \$1.0 million per day for each violation. This maximum penalty authority has been and will continue to be adjusted periodically to account for inflation. EPAct also amended the NGA to authorize FERC to "facilitate transparency in markets for the sale or transportation of physical natural gas in interstate commerce," pursuant to which authorization FERC now requires natural gas wholesale market participants, including a number of entities that may not otherwise be subject to FERC's traditional NGA jurisdiction, to report information annually to FERC concerning their natural gas sales and purchases. FERC requires any wholesale market participant that sells 2.2 million MMBtus or more annually in "reportable" natural gas sales to provide a report, known as FERC Form 552, to FERC. Reportable natural gas sales include sales of natural gas that utilize a daily or monthly gas price index, contribute to index price formation, or could contribute to index price formation, such as fixed price transactions for next-day or next-month delivery.

FERC also regulates interstate natural gas transportation rates, terms and conditions of service, and the terms under which we as a shipper may use interstate natural gas pipeline capacity, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas and for the release of our excess, if any, natural gas pipeline capacity. In 1985, FERC began promulgating a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate natural gas pipeline companies are required to provide non-unduly discriminatory transportation services to all shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC's initiatives have led to the development of a competitive, open access market for natural gas purchases, sales, and transportation that permits all purchasers of natural gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the less stringent regulatory approach currently pursued by FERC and Congress will continue indefinitely into the future nor can we determine what effect, if any, future regulatory changes might have on our natural gas related activities.

Under FERC's current regulatory regime, interstate transportation services must be provided on an open-access, non-unduly discriminatory basis at cost-based rates or negotiated rates, both of which are subject to FERC approval. The FERC also allows jurisdictional gas pipeline companies to charge market-based rates if the transportation market at issue is sufficiently competitive. The FERC-regulated tariffs, under which interstate pipelines provide such open-access transportation service, contain strict limits on the means by which a shipper releases its pipeline capacity to another potential shipper, which provisions require compliance with FERC's "shipper-must-have-title" rule. Violations by a shipper (i.e., a pipeline customer) of FERC's capacity release rules or shipper-must-have-title rule could subject a shipper to substantial penalties from FERC.

With respect to its regulation of natural gas pipelines under the NGA, FERC has not generally required the applicant for construction of a new interstate natural gas pipeline to provide information concerning the GHG emissions resulting from the activities of the proposed pipeline's customers. In August 2017, the U.S. Circuit Court of Appeals for the DC Circuit issued a decision remanding a natural gas pipeline certificate application to FERC, and required FERC to revise its environmental impact statement for the proposed pipeline to analyze potential GHG emission from the specific downstream power plants that the pipeline was designed to serve. To date, FERC has declined to analyze potential upstream GHG emissions that could result from the activities of natural gas producers and marketers, like the Company, to be served by proposed interstate natural gas pipeline projects. However, the scope of FERC's obligation to analyze the environmental impacts of proposed interstate natural gas pipeline projects, including the upstream indirect impacts of related natural gas production activity, remains subject to ongoing litigation and contested administrative proceedings at the FERC and in the courts.

Gathering service, which occurs on pipeline facilities located upstream of FERC-jurisdictional interstate transportation services, is regulated by the states onshore and in state waters. Under NGA section 1(b), gathering facilities are exempt from FERC's jurisdiction. FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, and FERC applies this test on a case-by-case basis. Depending on changes in the function performed by particular pipeline facilities, FERC has in the past reclassified certain FERC-jurisdictional transportation facilities as non-jurisdictional gathering facilities and FERC has reclassified certain non-jurisdictional gathering facilities as FERC-jurisdictional transportation facilities. Any such changes could result in an increase to our costs of transporting gas to point-of-sale locations.

The pipelines used to gather and transport natural gas being produced by the Company are also subject to regulation by the U.S. Department of Transportation ("DOT") under the Natural Gas Pipeline Safety Act of 1968, as amended, the Pipeline Safety Act of 1992, as reauthorized and amended ("Pipeline Safety Act"), and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. The DOT Pipeline and Hazardous Materials Safety Administration ("PHMSA") has established a risk-based approach to determine which gathering pipelines are subject to regulation and what safety standards regulated gathering pipelines must meet. In addition, PHMSA had initially considered regulations regarding, among other things, the designation of additional high consequence areas along pipelines, minimum requirements for leak detection systems, installation of emergency flow restricting devices, and revision of valve spacing requirements. In October 2019, PHMSA finalized new safety regulations for hazardous liquid pipelines, including a requirement that operators inspect affected pipelines following extreme weather events or natural disasters, that all hazardous liquid pipelines have a system for detecting leaks and that pipelines in high consequence areas be capable of accommodating in-line inspection tools within twenty years. In addition, PHMSA is in the process of finalizing a rulemaking with respect to gathering lines, but the contents and timing of any final rule for gathering lines are uncertain.

Oil and NGLs Sales and Transportation. Sales of oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

The Company's sales of oil and natural gas liquids are also affected by the availability, terms and costs of transportation. The rates, terms, and conditions applicable to the interstate transportation of oil and natural gas liquids by pipelines are regulated by FERC under the Interstate Commerce Act ("ICA"). FERC has implemented a simplified and generally applicable ratemaking methodology for interstate oil and natural gas liquids pipelines to fulfill the requirements of Title XVIII of the Energy Policy Act of 1992 comprised of an indexing system to establish ceilings on interstate oil and natural gas liquids pipeline rates. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil and natural gas liquid transportation rates will not affect our operations in any materially different way than such regulation will affect the operations of our competitors.

Further, interstate common carrier oil pipelines must provide service on a non-duly discriminatory basis under the ICA, which is administered by FERC. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

In addition, FERC issued a declaratory order in November 2017, involving a marketing affiliate of an oil pipeline, which held that certain arrangements between an oil pipeline and its marketing affiliate would violate the ICA's anti-discrimination provisions. FERC held that providing transportation service to affiliates at what is essentially the variable cost of the movement, while requiring non-affiliated shippers to pay the filed tariff rate, would violate the ICA. Rehearing has been sought of this FERC order by various parties. Due to the pending rehearing of the order and its recency, the Company cannot currently determine the impact this FERC order may have on oil pipelines, their marketing affiliates, and the price of oil and other liquids transported by such pipelines.

Any transportation of the Company's oil, natural gas liquids and purity components (ethane, propane, butane, iso-butane, and natural gasoline) by rail is also subject to regulation by the DOT's PHMSA and the DOT's Federal Railroad Administration ("FRA") under the Hazardous Materials Regulations at 49 CFR Parts 171-180, including Emergency Orders by the FRA regulations initially established on May 8, 2015 by PHMSA, arising due to the consequences of train accidents and the increase in the rail transportation of flammable liquids; PHMSA regulations were subsequently amended to remove certain requirements on September 25, 2018.

State Regulation. Texas regulates the drilling for, and the production, gathering and sale of, oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. Texas currently imposes a 4.6% severance tax on oil production and a 7.5% severance tax on natural gas production. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and natural gas resources. States may regulate rates of production and may establish maximum daily production allowables from oil and natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but we cannot assure you that they will not do so in the future. The effect of these regulations may be to limit the amount of oil and natural gas that may be produced from our wells and to limit the number of wells or locations we can drill.

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us.

Financial Regulations, Including Regulations Enacted Under the Dodd-Frank Act. The U.S. Commodities and Futures Exchange Commission ("CFTC") holds authority to monitor certain segments of the physical and futures energy commodities market including oil and natural gas. With regard to physical purchases and sales of natural gas and other energy commodities, and any related hedging activities that the Company undertakes, the Company is thus required to observe anti-market manipulation and disruptive trading practices laws and related regulations enforced by the FERC and/or the CFTC. The CFTC also holds substantial enforcement authority, including the ability to assess civil penalties.

Congress adopted comprehensive financial reform legislation in 2010, establishing federal oversight and regulation of the over-the-counter derivative market and entities that participate in that market. The legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank Act"), required the CFTC and the U.S. Securities and Exchange Commission ("SEC") to promulgate rules and regulations implementing the legislation, including regulations that affecting derivatives contracts that the Company uses to hedge its exposure to price volatility.

While the CFTC and the SEC have issued final regulations in certain areas, final rules in other areas remain pending, including a proposal to set position limits for certain futures and options contracts in various commodities and for swaps that are their economic equivalents. The CFTC also has proposed, but not yet finalized, a rule regarding the capital posting requirements for swap dealers and major swap market participants. The Company cannot, at this time, predict the timing or contents of any final rules the CFTC may enact with regard to either rulemaking proceeding. Any final rule in either proceeding could impact the Company's ability to enter into financial derivative transactions to hedge or mitigate exposure to commodity price volatility and other commercial risks affecting our business.

Worker Health and Safety. We are subject to a number of federal and state laws and regulations, including OSHA, and comparable state statutes, the purpose of which are to protect the health and safety of workers. In 2016, there were substantial revisions to the regulations under OSHA that may have impact to our operations. These changes include among other items; record keeping and reporting, revised crystalline silica standard (which requires the oil and gas industry to implement engineering controls and work practices to limit exposures below the new limits by June 23, 2021), naming oil and gas as a high hazard industry and requirements for a safety and health management system. In addition, OSHA's hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations, and that this information be provided to employees, state and local government authorities and citizens.

Commitments and Contingencies

The Company's activities are subject to federal, state and local laws and regulations governing environmental quality and pollution control. Although no assurances can be made, the Company believes that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, rules and regulations governing the release of materials into the environment or otherwise relating to the protection of the environment will not have a material effect upon the capital expenditures, earnings or the competitive position of the Company with respect to its existing assets and operations. The Company cannot predict what effect additional regulation or legislation, enforcement policies included, and claims for damages to property, employees, other persons, and the environment resulting from the Company's operations could have on its activities. See "Note 17 - Commitments and Contingencies" of the Notes to our Consolidated Financial Statements for additional information.

Available Information

We make available free of charge on our website (www.callon.com) our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other filings pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, and amendments to such filings, as soon as reasonably practicable after each are electronically filed with, or furnished to, the SEC.

We also make available within the "About Callon" section of our website our Code of Business Conduct and Ethics, Corporate Governance Guidelines, and Audit, Compensation, Strategic Planning and Reserves, and Nominating and Corporate Governance Committee Charters, which have been approved by our Board of Directors. We will make timely disclosure on our website of any change to, or waiver from, the Code of Business Conduct and Ethics for our principal executive and senior financial officers. A copy of our Code of Business Conduct and Ethics is also available, free of charge by writing us at: General Counsel, Callon Petroleum Company, 2000 W. Sam Houston Parkway South, Suite 2000, Houston, TX 77042.

ITEM 1A. Risk Factors

Risks Related to the Oil & Natural Gas Industry

Oil and natural gas prices are volatile, and substantial or extended declines in prices may adversely affect our results of operations and financial condition. Our success is highly dependent on prices for oil and natural gas, which have in recent years been, and we expect will continue to be, extremely volatile. During the five years ended December 31, 2019, NYMEX WTI prices ranged from a high of $77.41 per barrel on June 27, 2018 to a low of $26.19 per barrel on February 11, 2016, and NYMEX Henry Hub prices ranged from a high of $6.24 per MMBtu on January 2, 2018 to a low of $1.49 per MMBtu on March 4, 2016. The prices of oil and natural gas depend on factors we cannot control, such as macro-economic conditions, levels of production, domestic and worldwide inventories, demand for oil and natural gas, the capacity of U.S. and international refiners to use U.S. supplies of oil, natural gas and NGLs, relative price and availability of alternative forms of energy, actions by non-governmental organizations, OPEC and other countries, legislative and regulatory actions, technology developments impacting energy consumption and energy supply, and weather. These factors make it extremely difficult to predict future oil, natural gas and NGLs price movements with any certainty. We make price assumptions that are used for planning purposes, and a significant portion of our cash outlays, including rent, salaries and noncancelable capital commitments, are largely fixed in nature. Accordingly, if commodity prices are below the expectations on which these commitments were based, our financial results are likely to be adversely and disproportionately affected because these cash outlays are not variable in the short term and cannot be quickly reduced to respond to unanticipated decreases in commodity prices.

In general, prices of oil, natural gas, and NGLs affect the following aspects of our business:

- our revenues, cash flows, earnings and returns;
- our ability to attract capital to finance our operations and the cost of the capital;
- the amount we are allowed to borrow under our Credit Facility;
- the profit or loss we incur in exploring for and developing our reserves; and
- the value of our oil and natural gas properties.

A substantial or extended decline in commodity prices may also reduce the amount of oil and natural gas that we can produce economically and cause a significant portion of our development projects to become uneconomic. This may result in our having to make significant downward adjustments to our estimated proved reserves. A reduction in production could also result in a shortfall in expected cash flows and require us to reduce capital spending, which could negatively affect our ability to replace our production and our future rate of growth, or require us to borrow funds to cover any such shortfall, which we may be unable to obtain at such time on satisfactory terms. As a result, a substantial or extended decline in commodity prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

If oil and natural gas prices remain depressed for extended periods of time, we may be required to make significant downward adjustments to the carrying value of our oil and natural gas properties. Under the full cost method, which we use to account for our oil and natural gas properties, the net capitalized costs of our oil and natural gas properties may not exceed the PV-10 of our estimated proved reserves, using the 12-Month Average Realized Price, plus the lower of cost or fair market value of our unproved properties. If such net capitalized costs exceed this limit, we must charge the amount of the excess to earnings. This type of charge will not affect our cash flows, but will reduce the book value of our stockholders' equity. We review the carrying value of our properties quarterly and once incurred, a write-down of oil and natural gas properties is not reversible at a later date, even if prices increase. See "Note 2 - Summary of Significant Accounting Policies" of the Notes to our Consolidated Financial Statements as well as the Supplemental Information on Oil and Natural Gas Operations for additional information.

Competitive industry conditions may negatively affect our ability to conduct operations. We compete with numerous other companies in virtually all facets of our business. Our competitors in development, exploration, acquisitions and production include major integrated oil and gas companies and smaller independents as well as numerous financial buyers. Some of our competitors may be able to pay more for desirable leases and evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources permit. We also compete for the materials, equipment, personnel and services that are necessary for the exploration, development and operation of our properties. Our ability to increase reserves in the future will be dependent on our ability to select and acquire suitable prospects for future exploration and development.

The unavailability or high cost of drilling rigs, pressure pumping equipment and crews, other equipment, supplies, water, personnel and oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget, which could materially and adversely affect our operations and profitability. From time to time, our industry experiences a shortage of drilling rigs, equipment, supplies, water or qualified personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, during periods in which the levels of exploration and production increase, the demand for, and wages and costs of, drilling rig crews and other experienced personnel, oilfield services and equipment typically also increase, while the quality of these services and equipment may suffer.

All of our producing properties are located in the Permian Basin of West Texas and the Eagle Ford Shale of South Texas, making us vulnerable to risks associated with operating in only two geographic regions. As a result of this concentration, as compared to companies that have a more diversified portfolio of properties, we may be disproportionately 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, availability of equipment, facilities, personnel or services, or market limitations or interruption of the processing or transportation of oil, natural gas or NGLs. Such delays, interruptions or limitations could have a material adverse effect on our financial condition and results of operations. In addition, the effect of fluctuations on supply and demand may be more pronounced within specific geographic oil and natural gas producing areas, which may cause these conditions to occur with greater frequency or magnify the effects of these conditions.

We may be unable to integrate successfully the operations of recent acquisitions with our operations, and we may not realize all the anticipated benefits of these acquisitions. We have completed, and may in the future complete, acquisitions that include undeveloped acreage. We can offer no assurance that we will achieve the desired profitability from our acquisitions, including the Carrizo Acquisition, or from any acquisitions we may complete in the future. In addition, failure to integrate recent and future acquisitions successfully could adversely affect our financial condition and results of operations.

Our acquisitions, including the recently completed Carrizo Acquisition, may involve numerous risks, including those relating to:

- operating a larger, more complex combined organization and adding operations;
- assimilating the assets and operations of the acquired business, especially if the assets acquired are in a new geographic area;
- acquired oil and natural gas reserves not being of the anticipated magnitude or as developed as anticipated;
- the loss of significant key employees, including from the acquired business;
- the inability to obtain satisfactory title to the assets we acquire;
- a decrease in our liquidity if we use a portion of our available cash to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- the diversion of management's attention from other business concerns, which could result in, among other things, performance shortfalls;
- the failure to realize expected profitability or growth;
- the failure to realize expected synergies and cost savings;
- coordinating geographically disparate organizations, systems and facilities;
- coordinating or consolidating corporate and administrative functions;
- inconsistencies in standards, controls, procedures and policies; and
- integrating relationships with customers, vendors and business partners.

Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. With respect to the Carrizo Acquisition in particular, we have incurred a number of costs associated with completing the Carrizo acquisition and expect to continue to incur significant costs to integrate the business of Carrizo. The elimination of duplicative costs, as well as the realization of other efficiencies related to the integration of our two companies, may not initially offset integration-related costs or achieve a net benefit in the near term or at all.

If we consummate any future acquisition, our capitalization and results of operation may change significantly, and you may not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in evaluating future acquisitions. The inability to effectively manage the integration of acquisitions could reduce our focus on current operations, which in turn, could negatively impact our future results of operations.

We may fail to fully identify problems with any properties we acquire, and as such, assets we acquire may prove to be worth less than we paid because of uncertainties in evaluating recoverable reserves and potential liabilities. We are actively seeking to acquire additional acreage in Texas or other regions in the future. Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, exploration potential, future oil and natural gas prices, adequacy of title, operating and capital costs, and potential environmental and other liabilities. Although we conduct a review that we believe is consistent with industry practices, we can give no assurance that we have identified or will identify all existing or potential problems associated with such properties or that we will be able to mitigate any problems we do identify. Such assessments are inexact and their accuracy is inherently uncertain. 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, title and environmental problems that may exist or arise. We are generally not entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. As a result of these factors, we may not be able to acquire oil and natural gas properties that contain economically recoverable reserves or be able to complete such acquisitions on acceptable terms.

Restrictions on our ability to obtain, recycle and dispose of water may impact our ability to execute our drilling and development plans in a timely or cost-effective manner. Water is an essential component of both the drilling and hydraulic fracturing processes. Historically, we have been able to secure water from local land owners and other third party sources for use in our operations. If drought conditions were to occur or demand for water were to outpace supply, our ability to obtain water could be impacted and in turn, our ability to perform hydraulic fracturing operations could be restricted or made more costly. Along with the risks of other extreme weather events, drought risk, in particular, is likely increased by climate change. 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, significant amounts of water are produced in our operations. Inadequate access to or availability of water recycling or water disposal facilities could adversely affect our production volumes or significantly increase the cost of our operations.

Factors beyond our control, including the availability and capacity of gas processing facilities and pipelines and other transportation operations owned and operated by third parties, affect the marketability of our production. The ability to market oil and natural gas from our wells depends upon numerous factors beyond our control. A significant factor in our ability to market our production is the availability and capacity of gas processing facilities and pipeline and other transportation operations, including trucking services, owned and operated by third parties. These facilities and services may be temporarily unavailable to us due to market conditions, physical or mechanical disruption, weather, lack of contracted capacity, pipeline safety issues, or other reasons. In addition, in certain newer development areas, processing and transportation facilities and services may not be sufficient to accommodate potential production and it may be necessary for new interstate and intrastate pipelines and gathering systems to be built. Our failure to obtain access to processing and transportation facilities and services on acceptable terms could materially harm our business. We may be required to shut in wells for lack of a market or because of inadequate or unavailable processing or transportation capacity. If that were to occur, we would be unable to realize revenue from those wells until transportation arrangements were made to deliver our production to market. Furthermore, if we were required to shut in wells, we might also be obligated to pay shut-in royalties to certain mineral interest owners in order to maintain our leases. If we were required to shut in our production for long periods of time due to lack of transportation capacity, it would have a material adverse effect on our business, financial condition, results of operations and cash flows.

Other factors that affect our ability to market our production include:

- the extent of domestic production and imports/exports of oil and natural gas;
- federal regulations authorizing exports of liquefied natural gas ("LNG"), the development of new LNG export facilities under construction in the U.S. Gulf Coast region, and the first LNG exports from such facilities;
- the construction of new pipelines capable of exporting U.S. natural gas to Mexico and transporting Eagle Ford Shale and Permian Basin oil production to the Gulf Coast;
- the proximity of hydrocarbon production to pipelines;
- the demand for oil and natural gas by utilities and other end users;
- the availability of alternative fuel sources;
- the effects of inclement weather; and
- state and federal regulation of oil, natural gas and NGL marketing and transportation.

We have entered into firm transportation contracts that require us to pay fixed sums of money regardless of quantities actually shipped. If we are unable to deliver the minimum quantities of production, such requirements could adversely affect our results of operations, financial position, and liquidity. We have entered into firm transportation agreements for a portion of our production in certain areas in order to improve our ability, and that of our purchasers, to successfully market our production. We may also enter into firm transportation arrangements for additional production in the future. These firm transportation agreements may be more costly than interruptible or short-term transportation agreements. Additionally, these agreements obligate us to pay fees on minimum volumes regardless of actual throughput. If we have insufficient production to meet the minimum volumes, the requirements to pay for quantities not delivered could have an impact on our results of operations, financial position, and liquidity.

Our estimated reserves are based on interpretations and assumptions that may be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves. This Annual Report contains estimates of our proved oil and natural gas reserves and the estimated future net cash flows from such reserves. The process of estimating oil and natural gas reserves is complex and requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir and is therefore inherently imprecise. These assumptions include those required by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from the estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this 2019 Annual Report on Form 10-K. Additionally, estimates of reserves and future cash flows may be subject to material downward or upward revisions, based on production history, development drilling and exploration activities and prices of oil and natural gas.

You should not assume that any PV-10 of our estimated proved reserves contained in this 2019 Annual Report on Form 10-K represents the market value of our oil and natural gas reserves. We base the PV-10 from our estimated proved reserves at December 31, 2019 on the 12-Month Average Realized Price and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Further, actual future net revenues will be affected by factors such as the amount and timing of actual development expenditures, the rate and timing of production, and changes in governmental regulations or taxes. Recovery of PUDs generally requires significant capital expenditures and successful drilling operations. Our reserve estimates include the assumption that we will make significant capital expenditures to develop these PUDs and the actual costs, development schedule, and results associated with these properties may not be as estimated. In addition, the discount factor used to calculate PV-10 may not be appropriate based on our cost of capital from time to time and the risks associated with our business and the oil and gas industry.

Unless we replace our oil and gas reserves, our reserves and production will decline. Our future oil and gas production depends on our success in finding or acquiring additional reserves. If we fail to replace reserves through drilling or acquisitions, our production, revenues, reserve quantities and cash flows will decline. In general, production from oil and gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. We may not be successful in finding, developing or acquiring additional reserves, and our efforts may not be economic. Our ability to make the necessary capital investment to maintain or expand our asset base of oil and gas reserves would be limited to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable.

Our identified drilling locations are scheduled to be drilled over many years, making them susceptible to uncertainties that could prevent them from being drilled or delay their drilling. Our management team has identified drilling locations as an estimation of our future development activities on our existing acreage. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these identified drilling locations depends on a number of uncertainties, including oil and natural gas prices, the availability and cost of capital, availability and cost of drilling, completion and production services and equipment, lease expirations, regulatory approvals, and other factors discussed in these risk factors. Because of these uncertain factors, we do not know if the identified drilling locations will ever be drilled or if we will be able to produce oil or natural gas from these drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the identified locations are located, the leases for such acreage will expire. Therefore, our actual drilling activities may materially differ from those presently identified.

Our exploration and development drilling efforts and the operation of our wells may not be profitable or achieve our targeted returns. Exploration, development, drilling and production activities are subject to many risks. We may invest in property, including undeveloped leasehold acreage, which we believe will result in projects that will add value over time. However, we cannot guarantee that any leasehold acreage acquired will be profitably developed, that new wells drilled will be productive or that we will recover all or any portion of our investment in such leasehold acreage or wells. Drilling for oil and natural gas may involve unprofitable efforts, including wells that are productive but do not produce sufficient net reserves to return a profit after deducting operating and other costs. In addition, we may not be successful in controlling our drilling and production costs to improve our overall return and wells that are profitable may not achieve our targeted rate of return. Wells may have production decline rates that are greater than anticipated. Future drilling and completion efforts may impact production from existing wells, and parent-child effects may impact future well productivity as a result of timing, spacing proximity or other factors. Failure to conduct our oil and gas operations in a profitable manner may result in write-downs of our proved reserves quantities, impairment of our oil and gas properties, and a write-down in the carrying value of our unproved properties, and over time may adversely affect our growth, revenues and cash flows.

The development of our PUDs may take longer and may require higher levels of capital expenditures than we currently anticipate. Developing PUDs requires significant capital expenditures, successful drilling operations, and a substantial amount of our proved reserves are PUDs which may not be ultimately developed or produced. Approximately 57% of our total estimated proved reserves as of December 31, 2019, were PUDs. The reserve data included in the reserve reports of our independent petroleum engineers assume significant capital expenditures will be made to develop such reserves. We cannot be certain that the estimated capital expenditures to develop these reserves are accurate, that development will occur as scheduled, or that the results of such development will be as estimated. We may be forced to limit, delay or cancel drilling operations as a result of a variety of factors, including: unexpected drilling conditions; pressure or irregularities in formations; lack of proximity to and shortage of capacity of transportation facilities; equipment failures or accidents and shortages or delays in the availability of drilling rigs, equipment, personnel and services; and compliance with governmental requirements. Delays in the development of our reserves, increases in costs to drill and develop such reserves or decreases in commodity prices will reduce the future net revenues of our estimated PUDs and may result in some projects becoming uneconomical. In addition, delays in the development of reserves could force us to reclassify certain of our proved reserves as unproved reserves.

The results of our planned development programs in new or emerging shale development areas and formations may be subject to more uncertainties than programs in more established areas and formations, and may not meet our expectations for reserves or production. The results of our horizontal drilling efforts in emerging areas and formations of the Permian Basin are generally more uncertain than drilling results in areas that are more developed and have more established production from horizontal formations. Because emerging areas and associated target formations have limited or no production history, we are less able to rely on past drilling results in those areas as a basis to predict our future drilling results. In addition, horizontal wells drilled in shale formations, as distinguished from vertical wells, utilize multilateral wells and stacked laterals, all of which are subject to well spacing, density and proration requirements of the Texas Railroad Commission (the "RRC"), which requirements could adversely impact our ability to maximize the efficiency of our horizontal wells related to reservoir drainage over time. Further, access to adequate gathering systems or pipeline takeaway capacity and the availability of drilling rigs and other services may be more challenging in new or emerging areas. If our drilling results in these areas are less than anticipated or we are unable to execute our drilling program in these areas because of capital constraints, access to gathering systems and takeaway capacity or otherwise, or natural gas and oil prices decline, our investment in these areas may not be as economic as we anticipate, we could incur material write-downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

Our operations are subject to operating hazards that may adversely impact our ability to conduct business, and we may not be fully insured against all such operating risks. The operating hazards in exploring for and producing oil and natural gas include: encountering unexpected subsurface conditions that cause damage to equipment or personal injury, including loss of life; equipment failures that curtail or stop production or cause severe damage to or destruction of property, natural resources or other equipment; blowouts or other damages to the productive formations of our reserves that require a well to be re-drilled or other corrective action to be taken; and storms and other extreme weather conditions that cause damages to our production facilities or wells. Because of these or other events, we could experience environmental hazards, including release of oil and natural gas from spills, natural gas leaks, accidental leakage of toxic or hazardous materials, such as petroleum liquids, drilling fluids or fracturing fluids, including chemical additives, underground migration, and ruptures. If we experience any of these problems, we could incur substantial losses in excess of our insurance coverage.

The occurrence of a significant event or claim, not fully insured or indemnified against, could have a material adverse effect on our financial condition and operations. In accordance with industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. Also, no assurance can be given that we will be able to maintain insurance in the future at rates we consider reasonable to cover our possible losses from operating hazards and we may elect no or minimal insurance coverage.

Multi-well pad drilling may result in volatility in our operating results. We utilize multi-well pad drilling where practical. Because wells drilled on a pad are not brought into production until all wells on the pad are drilled and completed and the drilling rig is moved from the location, multi-well pad drilling delays the commencement of production. In addition, problems affecting a single well could adversely affect production from all of the wells on the pad, which would further cause delays in the scheduled commencement of production or interruptions in ongoing production. These delays or interruptions may cause volatility in our operating results. Further, any delay, reduction or curtailment of our development and producing operations due to operational delays caused by multi-well pad drilling could result in the loss of acreage through lease expirations.

The loss of key personnel could adversely affect our ability to operate. We depend, and will continue to depend in the foreseeable future, on the services of our senior officers and other key employees, as well as other third-party consultants with extensive experience and expertise in evaluating and analyzing drilling prospects and producing oil and natural gas and maximizing production from oil and natural gas properties. Our ability to retain our senior officers, other key employees, and third party consultants, many of whom are not subject to employment agreements, is important to our future success and growth. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on our business.

We may not be able to keep pace with technological developments in our industry. The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage or may be forced by competitive pressures to implement those new technologies at substantial costs. We may not be able to respond to these competitive pressures or implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete, our business, financial condition or results of operations could be materially and adversely affected.

Our business could be negatively affected by security threats. A cyberattack or similar incident could occur and result in information theft, data corruption, operational disruption, damage to our reputation or financial loss. The oil and natural gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development, production, processing and financial activities. We depend on digital technology to estimate quantities of oil and gas reserves, manage operations, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third party partners. Our technologies, systems, networks, seismic data, reserves information or other proprietary information, and those of our vendors, suppliers and other business partners, may become the target of cyberattacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or could otherwise lead to the disruption of our business operations or other operational disruptions in our exploration or production operations. Cyberattacks are becoming more sophisticated and certain cyber incidents, such as surveillance, may remain undetected for an extended period and could lead to disruptions in critical systems or the unauthorized release of confidential or otherwise protected information. These events could lead to financial losses from remedial actions, loss of business, disruption of operations, damage to our reputation or potential liability. Also, computers control nearly all of the oil and gas distribution systems in the United States and abroad, which are necessary to transport our production to market. A cyberattack directed at oil and gas distribution systems could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions. Cyber incidents have increased, and the U.S. government has issued warnings indicating that energy assets may be specific targets of cybersecurity threats. Our systems and insurance coverage for protecting against cybersecurity risks may not be sufficient. Further, as cyberattacks 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 vulnerability to cyberattacks.

We face various risks associated with increased activism against oil and natural gas exploration and development activities. Opposition toward oil and natural gas drilling and development activity has been growing globally and is particularly pronounced in the United States. Companies in the oil and natural gas industry are often the target of activist efforts from both individuals and non-governmental organizations regarding safety, human rights, environmental matters, sustainability, and business practices. Anti-development activists are working to, among other things, reduce access to federal and state government lands and delay or cancel certain operations such as drilling and development.

Risks Related to Financial Position

Our business requires significant capital expenditures and we may not be able to obtain needed capital or financing on satisfactory terms or at all. We make and expect to continue to make substantial capital expenditures in our business for the development, exploitation, production and acquisition of oil and natural gas reserves. Historically, we have funded our capital expenditures through a combination of cash flows from operations, borrowings from financial institutions, the sale of public debt and equity securities and asset dispositions. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, commodity prices, actual drilling results, participation of non-operating working interest owners, the cost and availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments.

If the borrowing base under our Credit Facility or our revenues decrease, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. The failure to obtain additional financing on terms acceptable to us, or at all, could result in a curtailment of our development activities and could adversely affect our business, financial condition and results of operations.

Our leverage and debt service obligations may adversely affect our financial condition, results of operations and business prospects. As of December 31, 2019, we had aggregate outstanding indebtedness of approximately $3.2 billion. As a result of the Carrizo Acquisition, our level of indebtedness has significantly increased. Our amount of indebtedness could affect our operations in many ways, including:

- requiring us to dedicate a substantial portion of our cash flow from operations to service our existing debt, thereby reducing the cash available to finance our operations and other business activities;
- limiting management's discretion in operating our business and our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- increasing our vulnerability to downturns and adverse developments in our business and the economy;
- limiting our ability to access the capital markets to raise capital on favorable terms or to obtain additional financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness;
- making it more likely that a reduction in our borrowing base following a periodic redetermination could require us to repay a portion of our then-outstanding bank borrowings;
- making us vulnerable to increases in interest rates as our indebtedness under our Credit Facility may vary with prevailing interest rates;
- placing us at a competitive disadvantage relative to competitors with lower levels of indebtedness or less restrictive terms governing their indebtedness; and
- making it more difficult for us to satisfy our obligations under our senior notes or other debt and increasing the risk that we may default on our debt obligations.

Restrictive covenants in the agreements governing our indebtedness may limit our ability to respond to changes in market conditions or pursue business opportunities. Our Credit Facility and the indentures governing our senior notes contain restrictive covenants that limit our ability to, among other things: incur additional indebtedness; make investments; merge or consolidate with another entity; pay dividends or make certain other payments; hedge future production or interest rates; create liens that secure indebtedness; sell assets; or engage in certain other transactions without the prior consent of the lenders. As a result of these covenants, we are limited in the manner in which we conduct our business and we may be unable to react to changes in market conditions, take advantage of business opportunities we believe to be desirable, obtain future financing, fund needed capital expenditures or withstand a continuing or future downturn in our business.

In addition, our Credit Facility requires us to maintain certain financial ratios and to make certain required payments of principal, premium, if any, and interest. If we fail to comply with these provisions or other financial and operating covenants in the Credit Facility or the indentures governing our senior notes, 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, cease making further loans and institute foreclosure proceedings against our assets; and we could be forced into bankruptcy or liquidation.

Our borrowings under our Credit Facility expose us to interest rate risk. Our earnings are exposed to interest rate risk associated with borrowings under our Credit Facility, which bear interest at a rate elected by us that is based on the prime, LIBOR or federal funds rate plus margins ranging from 0.25% to 2.25% depending on the interest rate used and the amount of the loan outstanding in relation to the borrowing base.

The borrowing base under our Credit Facility may be reduced below the amount of borrowings outstanding thereunder. The borrowing base under our Credit Facility is currently $2.5 billion, with an elected commitment amount of $2.0 billion, and as of December 31, 2019, we had an aggregate principal balance of $1.3 billion outstanding thereunder. Our borrowing base is subject to redeterminations semi-annually, and a future decrease in borrowing base due to the issuance of new indebtedness, the outcome of a subsequent borrowing base redetermination or an unwillingness or inability on the part of lending counterparties to meet their funding obligations may cause us to not be able to access adequate funding under the Credit Facility. If our borrowing base were to be reduced, we may be unable to implement our drilling and development plan, make acquisitions or otherwise carry out business plans, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness. In addition, we cannot borrow amounts above the elected commitments, even if the borrowing base is greater, without new commitments being obtained from the lenders for such incremental amounts above the elected commitments. In the event the amount outstanding under our Credit Facility exceeds the elected commitments, we must repay such amounts immediately in cash. In the event the amount outstanding under our Credit Facility exceeds the redetermined borrowing base, we are required to either (i) grant liens on additional oil and gas properties (not previously evaluated in determining such borrowing base) with a value equal to or greater than such excess, (ii) repay such excess borrowings over six monthly installments, or (iii) elect a combination of options in clauses (i) and (ii). We may not have sufficient funds to make any required repayment. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowings or arrange new financing, an event of default would occur under our Credit Facility.

We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy our obligations under applicable debt instruments, which may not be successful. Our ability to make scheduled payments on or to refinance our indebtedness obligations depends on our financial condition and operating performance, which are subject to certain financial, economic, competitive and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness.

If our cash flows and capital resources are insufficient to fund debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional capital or restructure or refinance indebtedness. These alternative measures may not be successful and may not permit us to meet scheduled debt service obligations. Our ability to restructure or refinance indebtedness will depend on the condition of the capital markets and our financial condition at such time. Also, we may not be able to consummate dispositions at such time on terms acceptable to us or at all, and the proceeds of any such dispositions may not be adequate to meet such debt service obligations. Furthermore, any refinancing of indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict business operations. In addition, the terms of existing or future debt instruments may restrict us from adopting some of these alternatives. For example, our Credit Facility currently restricts our ability to dispose of assets and our use of the proceeds from such disposition.

Any failure to make payments of interest and principal on outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness.

We cannot be certain that we will be able to maintain or improve our leverage position. An element of our business strategy involves maintaining a disciplined approach to financial management. However, we are also seeking to acquire, exploit and develop additional reserves that may require the incurrence of additional indebtedness. Although we will seek to maintain or improve our leverage position, our ability to maintain or reduce our level of indebtedness depends on a variety of factors, including future performance and our future debt financing needs. General economic conditions, oil and natural gas prices and financial, business and other factors will also affect our ability to maintain or improve our leverage position. Many of these factors are beyond our control.

Our hedging program may limit potential gains from increases in commodity prices, result in losses, or be inadequate to protect us against continuing and prolonged declines in commodity prices. We enter into arrangements to hedge a portion of our production from time to time to reduce our exposure to fluctuations in oil and natural gas prices and to achieve more predictable cash flow. Our hedges at December 31, 2019 are in the form of collars, swaps, put and call options, basis swaps, and other structures placed with the commodity trading branches of certain national banking institutions and with certain other commodity trading groups. These hedging arrangements may limit the benefit we could receive from increases in the market or spot prices for oil and natural gas. We cannot be certain that the hedging transactions we have entered into, or will enter into, will adequately protect us from continuing and prolonged declines in oil and natural gas prices. To the extent that oil and natural gas prices remain at current levels or decline further, we would not be able to hedge future production at the same pricing level as our current hedges and our results of operations and financial condition may be negatively impacted.

In addition, in a typical hedge transaction, we will have the right to receive from the other parties to the hedge the excess of the fixed price specified in the hedge over a floating price based on a market index, multiplied by the quantity hedged. If the floating price exceeds the fixed price, we are required to pay the other parties this difference multiplied by the quantity hedged regardless of whether we have sufficient production to cover the quantities specified in the hedge. Significant reductions in production at times when the floating price exceeds the fixed price could require us to make payments under the hedge agreements even though such payments are not offset by sales of physical production.

Our hedging transactions expose us to counterparty credit risk. Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract, particularly during periods of falling commodity prices. Disruptions in the financial markets or other factors outside our control could lead to sudden decreases in a counterparty's liquidity, which could make them unable to perform under the terms of the derivative contract. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform, and even if we do accurately predict sudden changes, our ability to negate the risk may be limited depending on market conditions at the time. If the creditworthiness of any of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss.

The inability of one or more of our customers to meet their obligations to us may adversely affect our financial results. Our principal exposure to credit risk is through receivables resulting from the sale of our oil and natural gas production, advances to joint interest parties and joint interest receivables. We are also subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. The largest purchaser of our oil and natural gas accounted for approximately 26% of our total revenues for the year ended December 31, 2019. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Our ability to use our existing net operating loss carryforwards or other tax attributes could be limited. A portion of our NOL carryforward balance was generated prior to the effective date of new limitations on utilization of NOLs imposed by the Tax Cuts and Jobs Act of 2017 (the "Tax Act") and are allowable as a deduction against 100 percent of taxable income in future years but will start to expire in the tax year 2035. The remainder was generated following such effective date and thus are allowable as a deduction against 80 percent of taxable income in future years and do not expire. Utilization of any NOL carryforwards depends on many factors, including our ability to generate future taxable income, which cannot be assured. In addition, Section 382 of the Internal Revenue Code of 1986, as amended ("Section 382"), generally imposes, upon the occurrence of an ownership change (discussed below), an annual limitation on the amount of our pre-ownership change NOLs we can utilize to offset our taxable income in any taxable year (or portion thereof) ending after such ownership change. The limitation is generally equal to the value of our stock immediately prior to the ownership change multiplied by the long-term tax exempt rate. In general, an ownership change occurs if there is a cumulative increase in our ownership of more than 50 percentage points by one or more "5% shareholders" (as defined in the Internal Revenue Code of 1986, as amended) at any time during a rolling three-year period. The Company has reduced the total recorded NOL balance and associated deferred tax asset for the NOLs to the amount expected to be fully utilizable before they expire. Future ownership changes or future regulatory changes could further 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.

Unanticipated changes in effective tax rates or adverse outcomes resulting from examination of our income or other tax returns could adversely affect our financial condition and results of operations.

We are subject to income taxes in the U. S., and our domestic tax assets and liabilities are subject to the allocation of expenses in differing jurisdictions. Our future effective tax rates could be subject to volatility or adversely affected by a number of factors, including:

- changes in the valuation of our deferred tax assets and liabilities;
- expected timing and amount of the release of any tax valuation allowances;
- tax effects of stock-based compensation;
- costs related to intercompany restructurings;
- changes in tax laws, regulations or interpretations thereof; or
- lower than anticipated future earnings in our taxing jurisdictions.

In addition, we may be subject to audits of our income, sales and other transaction taxes by U.S. federal and state authorities. Outcomes from these audits could have an adverse effect on our financial condition and results of operations.

Adverse changes in our credit rating may affect our borrowing capacity and borrowing terms. Our outstanding debt is periodically rated by nationally recognized credit rating agencies. The credit ratings are based on our operating performance, liquidity and leverage ratios, overall financial position, and other factors viewed by the credit rating agencies as relevant to our industry and the economic outlook. Our credit rating may affect the amount of capital we can access, as well as the terms of any financing we may obtain. Because we rely in part on debt financing to fund growth, adverse changes in our credit rating may have a negative effect on our future growth.

A negative shift in investor sentiment of the oil and gas industry could adversely affect our ability to raise debt and equity capital. Certain segments of the investor community have developed negative sentiment towards investing in our industry. Recent equity returns in the sector versus other industry sectors have led to lower oil and gas representation in certain key equity market indices. In addition, some investors, including investment advisors and certain sovereign wealth funds, pension funds, university endowments and family foundations, have stated policies to disinvest in the oil and gas sector based on their social and environmental considerations. Certain other stakeholders have also pressured commercial and investment banks to stop financing oil and gas production and related infrastructure projects. Such developments, including environmental activism and initiatives aimed at limiting climate change and reducing air pollution, could result in downward pressure on the stock prices of oil and gas companies, including ours. This may also potentially result in a reduction of available capital funding for potential development projects, impacting our future financial results.

Legal and Regulatory Risks

We are subject to stringent and complex federal, state and local laws and regulations which require compliance that could result in substantial costs, delays or penalties. Our oil and natural gas operations are subject to various federal, state and local governmental regulations that may be changed from time to time in response to economic and political conditions. For a discussion of the material regulations applicable to us, see "Business and Properties—Regulations." These laws and regulations may:

- require that we acquire permits before commencing drilling;
- regulate the spacing of wells and unitization and pooling of properties;
- impose limitations on production or operational, emissions control and other conditions on our activities;
- restrict the substances that can be released into the environment or used in connection with drilling and production activities or restrict the disposal of waste from our operations;
- limit or prohibit drilling activities on protected areas, such as wetlands and wilderness;
- impose penalties or other sanctions for accidental or unpermitted spills or releases from our operations; or
- require measures to remediate or mitigate pollution and environmental impacts from current and former operations, such as cleaning up spills or dismantling abandoned production facilities.

Significant expenditures may be required to comply with governmental laws and regulations applicable to us. In addition, failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, permit revocations, requirements for additional pollution controls or injunctions limiting or prohibiting operations.

The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal, state and local agencies frequently revise environmental laws and regulations, and such changes could result in increased costs for environmental compliance, such as emissions control, permitting, or waste handling, storage, transport, remediation or disposal for the oil and natural gas industry and could have a significant impact on our operating costs. In general, the oil and natural gas industry recently has been the subject of increased legislative and regulatory attention with respect to public health and environmental matters. Even if regulatory burdens temporarily ease, the historic trend of more expansive and stricter environmental legislation and regulations may continue in the long-term.

Further, under these laws and regulations, we could be liable for costs of investigation, removal and remediation, damages to and loss of use of natural resources, loss of profits or impairment of earning capacity, property damages, costs of increased public services, as well as administrative, civil and criminal fines and penalties, and injunctive relief. Certain environmental statutes, including the RCRA, CERCLA, OPA and analogous state laws and regulations, impose strict, joint and several liability for costs required to investigate, clean up and restore sites where hazardous substances or other waste products have been disposed of or otherwise released (i.e., liability may be imposed regardless of whether the current owner or operator was responsible for the release or contamination or whether the operations were in compliance with all applicable laws at the time the release or contamination occurred). We could also be affected by more stringent laws and regulations adopted in the future, including any related to climate change, engine and other equipment emissions, GHGs and hydraulic fracturing. Under common law, we could be liable for injuries to people and property. We maintain limited insurance coverage for sudden and accidental environmental damages. We do not believe that insurance coverage for environmental damages that occur over time is available at a reasonable cost. Also, we do not believe that insurance coverage for the full potential liability that could be caused by sudden and accidental environmental damages is available at a reasonable cost. Accordingly, we may be subject to liability in excess of our insurance coverage or we may be required to curtail or cease production from properties in the event of environmental incidents.

Federal legislation and state and local legislative and regulatory initiatives relating to hydraulic fracturing and water disposal wells could result in increased costs and additional operating restrictions or delays. Hydraulic fracturing is used to stimulate production of hydrocarbons from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production and is typically regulated by state oil and gas commissions. However, from time to time, the U.S. Congress has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing. Legislation has been proposed in recent sessions of Congress to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of "underground injection" and to require federal permitting and regulatory control of hydraulic fracturing but has not passed. Furthermore, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, in February 2014, the EPA published permitting guidance addressing the use of diesel fuel in hydraulic fracturing operations, and issued an interpretive memorandum clarifying that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the Underground Injection Control program, specifically as "Class II" Underground Injection Control wells under the Safe Drinking Water Act. The EPA has also published air emission standards for certain equipment, processes and activities across the oil and natural gas sector, although the EPA proposed amendments in August 2019 that would rescind requirements related to the regulation of methane emissions. Additionally, the BLM published a final rule in March 2015 containing disclosure requirements and other mandates for hydraulic fracturing on federal and Indian lands. Although the BLM subsequently rescinded the rule in December 2017, the rescission has been challenged in federal court by several environmental groups and states. In November 2016, the BLM also issued rules to limit methane emissions from new and existing oil and gas operations on federal lands, but subsequently relaxed and rescinded certain requirements of the rules in September 2018; a lawsuit challenging the September 2018 rule revision is pending.

In some areas of Texas, including the Eagle Ford Shale and Permian Basin, there has been concern that certain formations into which disposal wells are injecting produced waters could become over-pressured after many years of injection, and the RRC is reviewing the data to determine whether any regulatory action is necessary to address this issue. If the RRC were to decline to issue permits for, or limit the volumes of, new injection wells into the formations that we currently utilize, we may be required to seek alternative methods of disposing of produced waters, including injecting into deeper formations, which could increase our costs.

Some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances, impose additional requirements on hydraulic fracturing activities or otherwise require the public disclosure of chemicals used in the hydraulic fracturing process. For example, Texas law requires the chemical components used in the hydraulic fracturing process, as well as the volume of water used, must be disclosed to the RRC and the public. Furthermore, the RRC issued the "well integrity rule" in May 2013, which includes testing and reporting requirements, such as (i) the requirement to submit to the RRC cementing reports after well completion or cessation of drilling, and (ii) the imposition of additional testing on wells less than 1,000 feet below usable groundwater. Additionally, in October 2014, the RRC adopted a rule requiring applicants for certain new water disposal wells to conduct seismic activity searches using the U.S. Geological Survey to determine the potential for earthquakes within a circular area of 100 square miles. The rule also clarifies the RRC's authority to modify, suspend or terminate a disposal well permit if scientific data indicates a disposal well is likely to contribute to seismic activity. The RRC has used this authority to deny permits for waste disposal wells. In addition to state law, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of drilling in general or hydraulic fracturing in particular.

In December 2016, the EPA released its final report "Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States." This report concludes that hydraulic fracturing can impact drinking water resources in certain circumstances but also noted that certain data gaps and uncertainties limited EPA's ability to fully characterize the severity of impacts or calculate the national frequency of impacts on drinking water resources from activities in the hydraulic fracturing water cycle. This study could result in additional regulatory scrutiny that could restrict our ability to perform hydraulic fracturing and increase our costs of compliance and doing business.

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, induced seismic activity, impacts on drinking water supplies, water usage and the potential for impacts to surface water, groundwater and the environment generally, and a number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic fracturing practices. Several states and municipalities have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances. If new laws or regulations that significantly restrict hydraulic fracturing or water disposal wells are adopted, such laws could make it more difficult or costly for us to drill for and produce oil and natural gas as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings. In addition, if hydraulic fracturing is further regulated at the federal, state or local level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements, permitting delays and potential increases in costs. These changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal, state or local laws governing hydraulic fracturing.

Climate change legislation or regulations restricting emissions of GHG, changes in the availability of financing for fossil fuel companies, and physical effects from climate change could adversely impact our operating costs and demand for the oil and natural gas we produce. In recent years, federal, state and local governments have taken steps to reduce emissions of GHGs. The EPA has finalized a series of GHG monitoring, reporting and emissions control rules, and the U.S. Congress has, from time to time, considered adopting legislation to reduce emissions. Several states have already taken measures to reduce emissions of GHGs primarily through the development of GHG emission inventories or regional GHG cap-and-trade programs. While we are subject to certain federal GHG monitoring and reporting requirements, our operations currently are not adversely impacted by existing federal, state and local climate change initiatives. For a description of existing and proposed GHG rules and regulations, see "Regulations."

In December 2015, the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change resulted in 195 countries, including the United States, coming together to develop the Paris Agreement, which calls for the parties to undertake "ambitious efforts" to limit the average global temperature. The Agreement went into effect on November 4, 2016, and establishes a framework for the parties to cooperate and report actions to reduce GHG emissions. The United States formally announced its intent to withdraw from the Paris Agreement on November 4, 2019, which withdrawal will become effective on November 4, 2020. Certain U.S. city and state governments have announced their intention to satisfy their proportionate obligations under the Paris Agreement. A number of states have begun taking actions to control or reduce emissions of GHGs. Restrictions on GHG emissions that may be imposed could adversely affect the oil and gas industry. The adoption of legislation or regulatory programs to reduce GHG emissions could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory requirements. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Moreover, incentives or requirements to conserve energy, use alternative energy sources, reduce GHG emissions in product supply chains, and increase demand for low-carbon fuel or zero-emissions vehicles, could reduce demand for the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our business, financial condition and results of operations.

In addition, fuel conservation measures, alternative fuel requirements and increasing consumer demand for alternatives to oil and natural gas could reduce demand for oil and natural gas. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could impact our business activities, operations and ability to access capital. Furthermore, some parties have initiated public nuisance claims under federal or state common law against certain companies involved in the production of oil and natural gas. As a result, private individuals or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury, property damages or other liabilities. Although our business is not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

Finally, most scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce significant physical effects, such as increased frequency and severity of droughts, storms, floods and other climatic events. If any such effects were to occur, they could adversely affect or delay demand for the oil or natural gas produced or cause us to incur significant costs in preparing for or responding to the effects of climatic events themselves. Potential adverse effects could include disruption of our production activities, including, for example, damages to our facilities from winds or floods or increases in our costs of operation or reductions in the efficiency of our operations, as well as potentially increased costs for insurance coverages in the aftermath of such effects.

Current or proposed financial legislation and rulemaking 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. Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") establishes federal oversight and regulation of over-the-counter derivatives and requires the U.S. Commodity Futures Trading Commission (the "CFTC") and the SEC to enact further regulations affecting derivative contracts, including the derivative contracts we use to hedge our exposure to price volatility through the over-the-counter market.

Although the CFTC and the SEC have issued final regulations in certain areas, final rules in other areas, including the scope of relevant definitions or exemptions, remain pending. In one of the CFTC's rulemaking proceedings still pending under the Dodd-Frank Act, the CFTC has proposed but not yet finalized position limits for certain futures and options contracts in various commodities and for swaps that are their economic equivalents (with exemptions for certain bona fide hedging transactions). Similarly, the CFTC has proposed but not yet finalized a rule regarding the capital that a swap dealer or major swap participant is required to post with respect to its swap business. The CFTC issued a final rule on margin requirements for uncleared swap transactions in January 2016, which it amended in November 2018. The final rule as amended includes an exemption for certain commercial end-users that enter into uncleared swaps in order to hedge bona fide commercial risks affecting their business. In addition, the CFTC has issued a final rule authorizing an exception from the requirement to use cleared exchanges (rather than hedging over-the-counter) for commercial end-users who use swaps to hedge their commercial risks. The Dodd-Frank Act also imposes recordkeeping and reporting obligations on counterparties to swap transactions and other regulatory compliance obligations. All of the above regulations could increase the costs to us of entering into financial derivative transactions to hedge or mitigate our exposure to commodity price volatility and other commercial risks affecting our business.

It is not possible at this time to predict the timing or contents of the CFTC's final rules on position limits or capital requirements. Depending on our ability to satisfy the CFTC's requirements for the various exemptions available for a commercial end-user using swaps to hedge or mitigate its commercial risks, the final rules may provide beneficial exemptions or may require us to comply with position limits and other limitations with respect to our financial derivative activities. When a final rule on capital requirements is issued, the Dodd-Frank Act may require our current counterparties to post additional capital as a result of entering into uncleared financial derivatives with us, which could increase the cost to us of entering into such derivatives. The Dodd-Frank Act may also require our current counterparties to financial derivative transactions to cease their current business as hedge providers or spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. These potential changes could reduce the liquidity of the financial derivatives markets which would reduce the ability of commercial end-users like us to hedge or mitigate their exposure to commodity price volatility. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of future swaps relative to the terms of our existing financial derivative contracts, and reduce the availability of derivatives to protect against commercial risks we encounter.

In addition, federal banking regulators have adopted new capital requirements for certain regulated financial institutions in connection with the Basel III Accord. The Federal Reserve Board also issued proposed regulations on September 30, 2016, proposing to impose higher risk-weighted capital requirements on financial institutions active in physical commodities, such as oil and natural gas. If and when these proposed regulations are fully implemented, financial institutions subject to these higher capital requirements may require that we provide cash or other collateral with respect to our obligations under the financial derivatives and other contracts in order to reduce the amount of capital such financial institutions may have to maintain. Alternatively, financial institutions subject to these capital requirements may require premiums to enter into derivatives and other physical commodity transactions to compensate for the additional capital costs for these transactions. Rules implementing the Basel III Accord and higher risk-weighted capital requirements could materially reduce our liquidity and increase the cost of derivative contracts and other physical commodity contracts (including through requirements to post collateral which could adversely affect our available capital for other commercial operations purposes).

If we reduce our use of derivative contracts as a result of any of the foregoing new requirements, our results of operations may become more volatile and cash flows less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Our revenues could be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations, or cash flows.

Tax laws and regulations may change over time, and the recently passed comprehensive tax reform bill could adversely affect our business and financial condition. On December 22, 2017, the President signed into law Public Law No. 115-97, a comprehensive tax reform bill commonly referred to as the Tax Act that significantly reforms the Internal Revenue Code of 1986, as amended (the "Code"). The Tax Act, among other things, (i) permanently reduces the U.S. corporate income tax rate, (ii) repeals the corporate alternative minimum tax, (iii) eliminates the deduction for certain domestic production activities, (iv) imposes new limitations on the utilization of net operating losses, and (v) provides for more general changes to the taxation of corporations, including changes to cost recovery rules and to the deductibility of interest expense, which may impact the taxation of oil and gas companies. The Tax Act is complex and far-reaching and we cannot predict with certainty the resulting impact its enactment has on us. The ultimate impact of the Tax Act may differ from our estimates due to changes in interpretations and assumptions made by us as well as additional regulatory guidance that may be issued and any such changes in interpretations or assumptions could adversely affect our business and financial condition. See "Note 12 - Income Taxes" to our consolidated financial statements included elsewhere in this 2019 Annual Report on Form 10-K for additional information.

In addition, from time to time, legislation has been proposed that, if enacted into law, would make significant changes to U.S. federal and state income tax laws, including (i) the elimination of the immediate deduction 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. While these specific changes were not included in the Tax Act, no accurate prediction can be made as to whether any such legislative changes will be proposed or enacted in the future or, if enacted, what the specific provisions or the effective date of any such legislation would be. The elimination of such U.S. federal tax deductions, as well as any other changes to or the imposition of new federal, state, local or non-U.S. taxes (including the imposition of, or increases in production, severance or similar taxes) could adversely affect our business and financial condition.

We may be subject to the actions of activist shareholders. We have been the subject of an activist shareholder in the past. Responding to shareholder activism can be costly and time-consuming, disrupt our operations and divert the attention of management and our employees from executing our business plan. Activist campaigns can create perceived uncertainties as to our future direction, strategy or leadership and may result in the loss of potential business opportunities, harm our ability to attract new investors, customers and joint venture partners and cause our stock price to experience periods of volatility or stagnation. Moreover, if individuals are elected to our Board of Directors with a specific agenda, our ability to effectively and timely implement our current initiatives, retain and attract experienced executives and employees and execute on our long-term strategy may be adversely affected.

Risks Related to our Common Stock

Our bylaws designate the Court of Chancery of the State of Delaware (the "Court of Chancery") as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our shareholders, which could limit our shareholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers, or other employees. Our bylaws provide that, unless we consent in writing to the selection of an alternative forum, the sole and exclusive forum for (i) any derivative action or proceeding brought on our behalf, (ii) any action or proceeding asserting a claim for breach of a fiduciary duty owed by any current or former director, officer, or other employee of our company to us or our shareholders, (iii) any action or proceeding asserting a claim against us or any current or former director, officer, or other employee of our company arising pursuant to any provision of the Delaware General Corporate Law (the "DGCL") or our charter or bylaws (as each may be amended from time to time), (iv) any action or proceeding asserting a claim against us or any current or former director, officer, or other employee of our company governed by the internal affairs doctrine, or (v) any action or proceeding as to which the DGCL confers jurisdiction on the Court of Chancery shall be the Court of Chancery or, if and only if the Court of Chancery lacks subject matter jurisdiction, any state court located within the State of Delaware or, if and only if such state courts lack subject matter jurisdiction, the federal district court for the District of Delaware, in all cases to the fullest extent permitted by law and subject to the court's having personal jurisdiction over the indispensable parties named as defendants.

Our exclusive forum provision is not intended to apply to claims arising under the Securities Act or the Exchange Act. To the extent the provision could be construed to apply to such claims, there is uncertainty as to whether a court would enforce the forum selection provision with respect to such claims, and in any event, our shareholders would not be deemed to have waived our compliance with federal securities laws and the rules and regulations thereunder.

Any person or entity purchasing or otherwise acquiring any interest in shares of our capital stock is deemed to have received notice of and consented to the foregoing forum selection provision. This provision may limit our shareholders' ability to bring a claim in a judicial forum that they find favorable for disputes with us or our directors, officers, or other employees, which may discourage such lawsuits.

Alternatively, if a court were to find this choice of forum provision inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect its business, financial condition, prospects, or results of operations.

Provisions of our charter documents and Delaware law may inhibit a takeover, which could limit the price investors might be willing to pay in the future for our common stock. Provisions in our certificate of incorporation and bylaws may have the effect of delaying or preventing an acquisition of the Company or a merger in which we are not the surviving company and may otherwise prevent or slow changes in our Board of Directors and management. In addition, because we are incorporated in Delaware, we are governed by the provisions of Section 203 of the DGCL. These provisions could discourage an acquisition of the Company or other change in control transactions and thereby negatively affect the price that investors might be willing to pay in the future for our common stock.

We have no current plans to pay cash dividends on our common stock. Our Credit Facility and the indentures governing our senior notes limit our ability to pay dividends and make other distributions. We have no current plans to pay dividends on our common stock and any future determination as to the declaration and payment of cash dividends will be at the discretion of our Board of Directors and will depend upon our financial condition, results of operations, contractual restrictions, capital requirements, business prospects and other factors deemed relevant by our Board of Directors at the time of such determination. Consequently, unless we revise our dividend plans, a shareholder's only opportunity to achieve a return on its investment in us will be by selling its shares of our common stock at a price greater than the shareholder paid for it. There is no guarantee that the price of our common stock that will prevail in the market will exceed the price at which a shareholder purchased its shares of our common stock.

Future sales of our common stock in the public market could reduce our stock price, and any additional capital raised by us through the sale of our common stock or other securities may dilute a shareholder's ownership in us. In the future, we may issue securities to raise capital. We may also acquire interests in other companies by using any combination of cash and our common stock or other 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 or have an adverse impact on the price of our common stock. In addition, secondary 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. Any such reduction in the market price of our common stock could impair our ability to raise additional capital through the sale of our securities.

ITEM 1B. Unresolved Staff Comments

None.

ITEM 3. Legal Proceedings

We are a defendant in various legal proceedings and claims, which arise in the ordinary course of our business. While the outcome of these events cannot be predicted with certainty, we believe that the ultimate resolution of any such actions will not have a material effect on our financial position or results of operations.

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 New York Stock Exchange under the symbol "CPE".

Holders

As of February 21, 2020 the Company had approximately 2,597 common stockholders of record.

Dividends

We have not paid any cash dividends on our common stock to date and presently do not expect to declare or pay any cash dividends on our common stock in the foreseeable future as we intend to reinvest our cash flows and earnings into our business and pay down debt. The declaration and payment of dividends is subject to the discretion of our Board of Directors and to certain limitations imposed under Delaware corporate law and the agreements governing our debt obligations. The timing, amount and form of dividends, if any, will depend on, among other things, our results of operations, financial condition, cash requirements and other factors deemed relevant by our Board of Directors. In addition, certain of our debt facilities contain restrictions on the payment of dividends to the holders of our common stock.

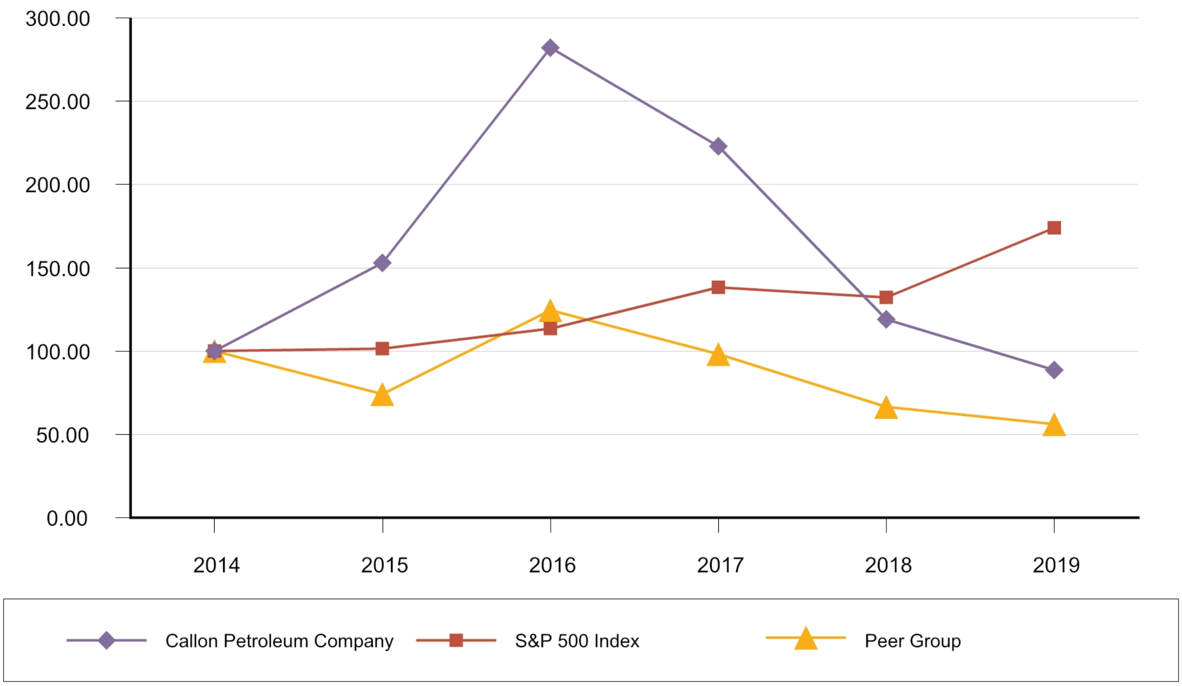
Performance Graph

The following stock price performance graph is intended to allow review of stockholder returns, expressed in terms of the performance of the Company's common stock relative to a broad-based stock performance index and a peer group of companies. The information is included for historical comparative purposes only and should not be considered indicative of future stock performance.

The graph below compares the yearly percentage change in the cumulative total stockholder return on the Company's common stock with the cumulative total return of the Standard & Poor's 500 Index ("S&P 500 Index") and a peer group of companies to which we compare our performance from December 31, 2014 through December 31, 2019. The companies in the peer group include Cimarex Energy Co., Centennial Resource Development, Inc., Magnolia Oil & Gas Corporation, Matador Resources, Inc., Oasis Petroleum, Inc., Parsley Energy, Inc., PDC Energy, Inc., QEP Resources, Inc., SM Energy Company, Whiting Petroleum Corporation, and WPX Energy, Inc.

The stock performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing

Comparison of Five Year Cumulative Total Return
Assumes Initial Investment of $100
December 31, 2019



	Years Ended December 31,					
Company/Market/Peer Group	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Callon Petroleum Company	$100	$153	$282	$223	$119	$89
S&P 500 Index - Total Returns	100	101	114	138	132	174
Peer Group	100	74	125	98	67	56

ITEM 6. Selected Financial Data

The following table sets forth, as of the dates and for the periods indicated, selected financial information about the Company. The financial information for each of the five years in the period ended December 31, 2019 has been derived from our audited Consolidated Financial Statements for such periods. The information should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Consolidated Financial Statements and Notes thereto. The following information is not necessarily indicative of our future results.

	Years Ended December 31,				
	2019	2018	2017	2016	2015
Statement of Operations Data [1]	(In thousands, except per share amounts)				
Oil, natural gas, and NGL revenue	$671,572	$587,624	$366,474	$200,851	$137,512
Total operating expenses	498,914	328,094	225,028	248,328	346,622
Income (loss) from operations	172,658	259,530	141,446	(47,477)	(209,110)
Income (loss) available to common stockholders [2]	67,928	300,360	120,424	(99,108)	(248,034)
Income (loss) available to common stockholders per common share:					
Basic	$0.24	$1.35	$0.56	($0.78)	($3.77)
Diluted	$0.24	$1.35	$0.56	($0.78)	($3.77)
Weighted average common shares outstanding:					
Basic	233,140	216,941	201,526	126,258	65,708
Diluted	233,550	217,596	202,102	126,258	65,708
Statement of Cash Flows Data					
Net cash provided by operating activities	$476,316	$467,654	$229,891	$120,774	$89,319
Net cash used in investing activities	(388,389)	(1,324,057)	(1,072,532)	(866,287)	(259,160)
Net cash provided by (used in) financing activities	(90,637)	844,459	217,643	1,397,282	170,097
Balance Sheet Data					
Total oil and natural gas properties	$6,669,118	$3,718,858	$2,513,491	$1,475,401	$711,386
Total assets	7,194,838	3,979,173	2,693,296	2,267,587	788,594
Long-term debt [3]	3,186,109	1,189,473	620,196	390,219	328,565
Stockholders' equity	3,223,308	2,445,208	1,855,966	1,733,402	362,758
Proved Reserves Data [4]					
Oil (MBbls)	346,361	180,097	107,072	71,145	43,348
Natural gas (MMcf)	757,134	350,466	179,410	122,611	65,537
NGLs (MBbls)	67,462	—	—	—	—
Total proved reserves (MBoe)	540,012	238,508	136,974	91,580	54,271
Standardized measure of discounted future net cash flows	$4,951,026	$2,941,293	$1,556,682	$809,832	$570,890

(1) Includes activity from the Carrizo Acquisition subsequent to the December 20, 2019 closing date.

(2) Net loss for 2015 included the recognition of a write-down of oil and natural gas properties of $208.4 million as a result of the ceiling test limitation and $108.8 million of income tax expense related to the recognition of a valuation allowance. Net loss for 2016 included the recognition of a write-down of oil and natural gas properties of $95.8 million as a result of the ceiling test limitation.

(3) See "Note 7 - Borrowings" of the Notes to our Consolidated Financial Statements for additional information.

(4) The estimated proved reserves acquired in the Carrizo Acquisition are presented on a three-stream basis and include NGLs, whereas, all other estimated proved reserve volumes are on a two-stream basis.

ITEM 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations

A discussion and analysis of the Company’s financial condition and results of operations for the year ended December 31, 2017 can be found in “Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations” of its Annual Report on Form 10-K for the year ended December 31, 2018, which was filed with the SEC on February 27, 2019 and is incorporated herein by reference.

General

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the accompanying audited consolidated financial statements, information about our business practices, significant accounting policies, risk factors, and the transactions that underlie our financial results, which are included in various parts of this filing.

Our website address is www.callon.com. All of our filings with the SEC are available free of charge through our website as soon as reasonably practicable after we file them with, or furnish them to, the SEC. Information on our website does not form part of this 2019 Annual Report on Form 10-K.

We are an independent oil and natural gas company incorporated in the State of Delaware in 1994, but our roots go back nearly 70 years to our Company’s establishment in 1950. We are focused on the acquisition, exploration and development of high-quality assets in the leading oil plays of South and West Texas. Our activities are primarily focused on horizontal development in the Midland and Delaware Basins, both of which are part of the larger Permian Basis in West Texas. In 2019, though our acquisition of Carrizo, we doubled our core acreage position in the Delaware Basin and entered the Eagle Ford Shale.

Our operating culture is centered on responsible development of hydrocarbon resources, safety and the environment, which we believe strengthens our operational performance. Our drilling activity is predominantly focused on the horizontal development of several prospective intervals in the Permian Basin, including multiple levels of the Wolfcamp formation and the Lower Spraberry shales, and more recently as a result of the Carrizo Acquisition, the Eagle Ford Shale. We have assembled a multi-year inventory of potential horizontal well locations and intend to add to this inventory through delineation drilling of emerging zones on our existing acreage and acquisition of additional locations through working interest acquisitions, leasing programs, acreage purchases, joint ventures and asset swaps.

Overview

Significant Accomplishments in 2019

- On December 20, 2019, we completed the Carrizo Acquisition which increased our portfolio to: (i) over 116,000 net acres in the Permian Basin, which doubled our footprint in the Southern Delaware Basin and (ii) expanded our portfolio to include over 76,000 net acres in the mature, high-margin, free cash flow generating Eagle Ford Shale.
- In connection with the Carrizo Acquisition, we entered into the Credit Facility, which has a maximum credit amount of $5.0 billion. As of December 31, 2019, the borrowing base under the Credit Facility was $2.5 billion, with an elected commitment amount of $2.0 billion.
- During 2019, we completed divestitures of non-core assets for aggregate net proceeds of $294.4 million. In addition, we could receive cash for settlements of our contingent consideration arrangement of up to $60.0 million if crude oil prices exceed specified thresholds for each of the years of 2019 through 2021.
- Our total production in 2019 increased by 26% to 15.1 MMBoe (77% oil) as compared to 2018.
- On July 18, 2019, we redeemed all of the outstanding Preferred Stock for $73.0 million.
- For the year ended December 31, 2019, we drilled 63 gross (55.7 net) horizontal wells, completed 55 gross (47.1 net) horizontal wells and had, as of December 31, 2019, 64 gross (57.7 net) horizontal wells awaiting completion.
- Estimated proved reserves as of December 31, 2019 were 540.0 MMBoe (64% oil), with 43% classified as proved developed.

Reserves Growth

As of December 31, 2019, our estimated proved reserves increased 126% to 540.0 MMBoe compared to 238.5 MMBoe of estimated proved reserves at year-end 2018. Our significant growth in proved reserves was primarily attributable to the Carrizo Acquisition, along with our horizontal development efforts. Our estimated proved reserves at year-end 2019 and 2018 were 64% and 76% oil, respectively.

Results of Operations

The following table sets forth certain operating information with respect to the Company's oil and natural gas operations for the periods indicated:

	Years Ended December 31,			
	2019 [(1)]	2018	$ Change	% Change
Total production [(2)]				
Oil (MBbls)	11,665	9,443	2,222	24%
Natural gas (MMcf)	19,718	15,447	4,271	28%
NGLs (MBbls)	135	—	135	100%
Total barrels of oil equivalent (MBoe)	15,086	12,018	3,068	26%
Total daily production (Boe/d)	41,331	32,926	8,405	26%
Oil as % of total daily production	77%	79%		
Average realized sales price (excluding impact of settled derivatives)				
Oil (per Bbl)	$54.27	$56.22	($1.95)	(3%)
Natural gas (per Mcf)	1.85	3.67	(1.82)	(50%)
NGLs (per Bbl)	15.37	—	15.37	100%
Total (per Boe)	44.52	48.90	(4.38)	(9%)
Average realized sales price (including impact of settled derivatives)				
Oil (per Bbl)	$53.31	$53.31	$—	—%
Natural gas (per Mcf)	2.22	3.69	(1.47)	(40%)
NGLs (per Bbl)	15.37	—	15.37	100%
Total (per Boe)	44.27	46.63	(2.36)	(5%)
Revenues (in thousands)				
Oil	$633,107	$530,898	$102,209	19%
Natural gas	36,390	56,726	(20,336)	(36%)
NGLs	2,075	—	2,075	100%
Total revenues	$671,572	$587,624	$83,948	14%
Additional per Boe data				
Lease operating expense [(3)]	6.09	5.76	0.33	6%
Production taxes	2.83	2.98	(0.15)	(5%)
Benchmark prices[(4)]				
WTI (per Bbl)	$56.98	$65.23	($8.25)	(13%)
Henry Hub (per Mcf)	2.56	3.15	(0.59)	(19%)

(1) Includes activity from the Carrizo Acquisition subsequent to the December 20, 2019 closing date.
(2) The production associated with reserves acquired in the Carrizo Acquisition are presented on a three-stream basis and include NGLs, whereas, all other reserve volumes are on a two-stream basis.
(3) Excludes gathering and treating expense.
(4) Reflects calendar average daily spot market prices.

Revenues

The following table is intended to reconcile the change in oil, natural gas, NGLs, and total revenue for the period presented by reflecting the effect of changes in volume and in the underlying commodity prices.

	Oil	Natural Gas	NGLs	Total
		(In thousands)		
Revenues for the year ended December 31, 2018	$530,898	$56,726	$—	$587,624
Volume increase (decrease)	124,869	15,683	2,075	142,627
Price increase (decrease)	(22,660)	(36,019)	—	(58,679)
Net increase (decrease)	102,209	(20,336)	2,075	83,948
Revenues for the year ended December 31, 2019 (1)(2)	$633,107	$36,390	$2,075	$671,572

(1) Includes activity from the Carrizo Acquisition subsequent to the December 20, 2019 closing date.
(2) The revenues associated with production from reserves acquired in the Carrizo Acquisition are presented on a three-stream basis and include NGLs, whereas, all other revenue is presented on a two-stream basis.

Commodity Prices

The prices for oil, natural gas, and NGLs remain extremely volatile and sometimes experience large fluctuations as a result of relatively small changes in supply, weather conditions, economic conditions and actions by OPEC and other countries and government actions. Prices of oil, natural gas, and NGLs will affect the following aspects of our business:

- our revenues, cash flows and earnings;
- the amount of oil and natural gas that we are economically able to produce;
- our ability to attract capital to finance our operations and cost of the capital;
- the amount we are allowed to borrow under the Credit Facility; and
- the value of our oil and natural gas properties.

Oil revenue

For the year ended December 31, 2019, oil revenues of $633.1 million increased $102.2 million, or 19%, compared to revenues of $530.9 million for the year ended December 31, 2018. The increase in oil revenue was primarily attributable to a 24% increase in production, partially offset by a 3% decrease in the average realized sales price, which declined to $54.27 per Bbl from $56.22 per Bbl. The increase in production was comprised of 3.2 MMBbls attributable to wells placed on production as a result of our horizontal drilling program, partially offset by normal and expected declines from our existing wells.

Natural gas revenue

Natural gas revenues decreased $20.3 million, or 36%, during the year ended December 31, 2019 to $36.4 million as compared to $56.7 million for the year ended December 31, 2018. The decrease primarily relates to an approximate 50% decrease in the average price realized, which declined to $1.85 per Mcf from $3.67 per Mcf. The decrease was partially offset by a 28% increase in natural gas volumes. The increase in production was comprised of 4.6 Bcf attributable to wells placed on production as a result of our horizontal drilling program, partially offset by normal and expected declines from our existing wells.

NGL revenue

We recognized NGL revenues of $2.1 million as a result of the recent Carrizo Acquisition.

Operating Expenses

	Years Ended December 31,							
		Per		Per	Total Change		Boe Change	
	2019	Boe	2018	Boe	$	%	$	%
	(In thousands, except per Boe and % amounts)							
Lease operating expenses	$91,827	$6.09	$69,180	$5.76	$22,647	33%	$0.33	6%
Production taxes	42,651	2.83	35,755	2.98	6,896	19%	(0.15)	(5%)
Depreciation, depletion and amortization	240,642	15.95	182,783	15.21	57,859	32%	0.74	5%
General and administrative	45,331	3.00	35,293	2.94	10,038	28%	0.06	2%
Merger and integration expenses	74,363	4.93	—	—	74,363	100%	4.93	100%
Settled share-based awards	3,024	0.20	—	—	3,024	100%	0.20	100%

Lease operating expenses. These are daily costs incurred to extract oil and natural gas and maintain our producing properties. Such costs also include maintenance, repairs, gas treating fees, salt water disposal, insurance and workover expenses related to our oil and natural gas properties.

Lease operating expenses for the year ended December 31, 2019 increased by 33% to $91.8 million compared to $69.2 million for the same period of 2018, primarily due to production volumes increasing 26%. Lease operating expense per Boe for the year ended December 31, 2019 increased to $6.09 compared to $5.76 for the same period of 2018 primarily due to increased non-operated activity related to previous acquisitions and workovers.

Production taxes. Production taxes include severance and ad valorem taxes. In general, severance taxes are based upon current year commodity prices whereas ad valorem taxes are based upon prior year commodity prices. Severance taxes are paid on produced oil and natural gas based on a percentage of revenues from products sold at fixed rates established by federal, state or local taxing authorities. In the counties where our production is located, we are also subject to ad valorem taxes, which are generally based on the taxing jurisdictions' valuation of our oil and gas properties. We benefit from tax credits and exemptions in our various taxing jurisdictions where available.

For the year ended December 31, 2019, production taxes increased 19% to $42.7 million compared to $35.8 million for the same period in 2018, due to an increase in severance taxes based on higher production volumes as well as an increase in ad valorem taxes due to a higher valuation of our oil and gas properties by the taxing jurisdictions and previous acquisitions. On a per Boe basis, production taxes for the year ended December 31, 2019 decreased by 5% compared to the same period of 2018. Also, production taxes as a percentage of total revenues for the year ended December 31, 2019 increased to 6.4% compared to 6.1% for the same period of 2018, due to higher ad valorem taxes as a result of higher valuations of our oil and gas properties during 2019.

Depreciation, depletion and amortization ("DD&A"). Under the full cost accounting method, we capitalize costs within a cost center and then systematically amortize those costs on an equivalent unit-of-production method based on production and estimated proved gas reserve quantities. Depreciation of other property and equipment is computed using the straight line method over their estimated useful lives, which range from three to twenty years.

For the year ended December 31, 2019, DD&A increased 32% to $240.6 million from $182.8 million compared to the same period of 2018. The increase is primarily attributable to a 26% increase in production, as discussed above, and a 5% increase in our DD&A per Boe rate. For the year ended December 31, 2019, DD&A per Boe increased to $15.95 compared to $15.21 for the same period of 2018.

General and administrative, net of amounts capitalized ("G&A"). G&A for the year ended December 31, 2019 increased to $45.3 million compared to $35.3 million for the same period of 2018. G&A for the periods indicated include the following:

	Years Ended December 31,			
	2019	**2018**	**$ Change**	**% Change**
	(In thousands, except % amounts)			
G&A	$37,174	$28,710	$8,464	29%
Share-based compensation	7,043	6,224	819	13%
Fair value adjustments of cash-settled RSU awards	672	359	313	87%
Fair value adjustments of cash-settled stock appreciation rights	442	—	442	100%
Total G&A expenses	$45,331	$35,293	$10,038	28%

Merger and integration expense. For the year ended December 31, 2019, the Company incurred $74.4 million of expenses associated with the Carrizo Acquisition. See "Note 4 – Acquisitions and Divestitures" of the Notes to our Consolidated Financial Statements for additional information regarding the merger with Carrizo.

Settled share-based awards. During the first quarter of 2019, the Company settled certain of the outstanding share-based award agreements of two former officers of the Company, resulting in $3.0 million recorded on the consolidated statements of operations.

Other Income and Expenses

	Years Ended December 31,			
	2019	**2018**	**$ Change**	**% Change**
	(In thousands, except % amounts)			
Interest expense	$81,399	$58,651	$22,748	39%
Capitalized interest	(78,492)	(56,151)	(22,341)	40%
Interest expense, net of capitalized amounts	2,907	2,500	407	16%
(Gain) loss on derivative contracts	$62,109	($48,544)	$110,653	(228%)

Interest expense, net of capitalized amounts. We finance a portion of our capital expenditures, acquisitions and working capital requirements with borrowings under our Credit Facility or with term debt. We incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We reflect interest paid to our lender in interest expense, net of capitalized amounts. In addition, we include the amortization of deferred financing costs (including origination and amendment fees), commitment fees and annual agency fees in interest expense.

Interest expense, net of capitalized amounts, incurred during the year ended December 31, 2019 increased $0.4 million to $2.9 million compared to $2.5 million for the same period of 2018.

Loss on extinguishment of debt. During December 2019, in connection with the Carrizo Acquisition, we entered into a new credit facility and simultaneously terminated our prior credit facility. As a result of terminating the prior credit facility, we recorded a loss on extinguishment of debt of $4.9 million, which was comprised solely of the write-off of unamortized deferred financing costs associated with the prior credit facility. See "Note 7 – Borrowings" of the Notes to our Consolidated Financial Statements for additional information.

Gain (loss) on derivative contracts. We utilize commodity derivative financial instruments to reduce our exposure to fluctuations in commodity prices. This amount represents the (i) gain (loss) related to fair value adjustments on our open derivative contracts and (ii) gains (losses) on settlements of derivative contracts for positions that have settled within the period.

For the year ended December 31, 2019, the net loss on derivative contracts was $62.1 million, compared to a $48.5 million net gain in 2018. The net gain (loss) on derivative contracts for the periods indicated includes the following:

	Years Ended December 31,		
	2019	2018	Change
	(In thousands)		
Oil derivatives			
Net gain (loss) on settlements	($11,188)	($27,510)	$16,322
Net gain (loss) on fair value adjustments	(62,125)	72,973	(135,098)
Total gain (loss) on oil derivatives	($73,313)	$45,463	($118,776)
Natural gas derivatives			
Net gain (loss) on settlements	$7,399	$238	$7,161
Net gain (loss) on fair value adjustments	1,490	2,843	(1,353)
Total gain (loss) on natural gas derivatives	$8,889	$3,081	$5,808
Contingent consideration arrangements			
Net gain (loss) on fair value adjustments	$2,315	$—	$2,315
Total gain (loss) on derivative contracts	($62,109)	$48,544	($110,653)

See "Note 8 - Derivative Instruments and Hedging Activities" and "Note 9 - Fair Value Measurements" of the Notes to our Consolidated Financial Statements for additional information.

Income tax expense. We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period the rate change is enacted. When appropriate based on our analysis, we record a valuation allowance for deferred tax assets when it is more likely than not that the deferred tax assets will not be realized.

The Company recorded income tax expense of $35.3 million for the year ended December 31, 2019 compared to $8.1 million for the same period of 2018. The change in income tax is primarily related to the change in the Company's tax position in the current period, as the Company no longer maintains a valuation allowance against its deferred tax assets. Current period income tax expense is comprised of both deferred federal and state income tax expense.

Preferred stock dividends. Holders of our Preferred Stock were entitled to receive, when, as and if declared by our Board of Directors, out of funds legally available for the payment of dividends, cumulative cash dividends at a rate of 10% per annum of the $50.00 liquidation preference per share (equivalent to $5.00 per annum per share).

Preferred stock dividends for the year ended December 31, 2019 decreased 45% to $4.0 million compared to $7.3 million in 2018. The decrease is attributable to the redemption of our preferred stock in July 2019. See "Note 11 – Stockholders' Equity" of the Notes to our Consolidated Financial Statements for additional information.

Loss on redemption of preferred stock. As a result of the redemption of our Preferred Stock mentioned above, we recognized an $8.3 million loss due to the excess of the $73.0 million redemption price over the $64.7 million redemption date carrying value. See "Note 11 – Stockholders' Equity" of the Notes to our Consolidated Financial Statements for additional information.

Liquidity and Capital Resources

Our primary uses of capital have historically been for the acquisition, development, and exploration of oil and natural gas properties. Our capital program could vary depending upon factors, including, but not limited to, the availability of drilling rigs and completion crews, the cost of completion services, acquisitions and divestitures of oil and gas properties, land and industry partner issues, our available cash flow and financing, success of drilling programs, weather delays, commodity prices, market conditions, the acquisition of leases with drilling commitments and other factors.

Historically, our primary sources of capital have been cash flows from operations, borrowings under our revolving credit facility, proceeds from the issuance of debt securities and public equity offerings, and non-core asset dispositions. As we pursue reserves and production growth, we regularly consider which resources, including debt and equity financings, are available to meet our future financial obligations, planned capital expenditures and liquidity requirements.

Overview of Cash Flow Activities. For the year ended December 31, 2019, cash and cash equivalents decreased $2.7 million to $13.3 million compared to $16.1 million at December 31, 2018.

	Years Ended December 31, 2019	Years Ended December 31, 2018
	(In thousands)	
Net cash provided by operating activities	$476,316	$467,654
Net cash used in investing activities	(388,389)	(1,324,057)
Net cash provided by (used in) financing activities	(90,637)	844,459
Net change in cash and cash equivalents	($2,710)	($11,944)

Operating activities. Net cash provided by operating activities was $476.3 million and $467.7 million for the years ended December 31, 2019 and 2018, respectively. The change in operating activities was predominantly attributable to the following:

- An increase in revenue due to higher production volumes, offset by a decrease in realized pricing;
- An offsetting increase in operating expenses as a result of higher production volumes;
- An offsetting increase in cash G&A expense due to increase personnel costs, and;
- Changes related to timing of working capital payments and receipts.

Production, realized prices, and operating expenses are discussed below in Results of Operations. See "Note 8 – Derivative Instruments and Hedging Activities" and "Note 9 – Fair Value Measurements" of the Notes to our Consolidated Financial Statements for a reconciliation of the components of the Company's derivative contracts and disclosures related to derivative instruments including their composition and valuation.

Investing activities. Net cash used in investing activities was $388.4 million and $1,324.1 million for the years ended December 31, 2019 and 2018, respectively. The change in investing activities was primarily attributable to the following:

- A $285.4 million increase in proceeds received from the sale of non-core assets as compared to the year ended December 31, 2018.
- A $676.5 million decrease in acquisitions.
- A $29.4 million increase in capital expenditures due to increased activity from our 2019 development program, focused on multi-well pads, as well as additional investments in facilities and infrastructure.

Our investing activities, on a cash basis, include the following for the periods indicated:

	Years Ended December 31, 2019	Years Ended December 31, 2018	$ Change
		(In thousands)	
Operational expenditures	$520,614	$537,514	($16,900)
Seismic, leasehold and other	8,984	8,555	429
Capitalized general and administrative costs	31,612	24,383	7,229
Capitalized interest	79,330	40,721	38,609
Total capital expenditures (1)	$640,540	$611,173	$29,367
Acquisitions	$42,266	$718,793	($676,527)
Proceeds from the sale of assets	(294,417)	(9,009)	(285,408)
Additions to other assets	—	3,100	(3,100)
Total investing activities	$388,389	$1,324,057	($935,668)

(1) Includes activity from the Carrizo Acquisition subsequent to the December 20, 2019 closing date.

On an accrual basis, which is the methodology used for establishing our annual capital budget, operational expenditures for the year ended December 31, 2019 were $506.1 million. Inclusive of seismic, leasehold and other, capitalized general and administrative, and capitalized interest costs, total capital expenditures for the year ended December 31, 2019 were $629.7 million.

General and administrative expenses and capitalized interest are discussed below in Results of Operations. See “Note 4 – Acquisitions and Divestitures” and “Note 17 – Commitments and Contingencies” of the Notes to our Consolidated Financial Statements for additional information on significant acquisitions and drilling rig leases.

Financing activities. We finance a portion of our capital expenditures, acquisitions and working capital requirements with borrowings under our credit facility, term debt and equity offerings. For the year ended December 31, 2019, net cash used in financing activities was $90.6 million compared to net cash provided by financing activities of $844.5 million during the same period of 2018. The change in net cash provided by (used in) financing activities was primarily attributable to the following:

- Repayment of Carrizo’s credit facility and funded the redemption of preferred stock upon closing the Carrizo Acquisition.
- Redemption of Preferred Stock for approximately $73.0 million in 2019.
- Completed an underwritten public offering of 25.3 million shares of common stock for total estimated net proceeds of approximately $288.0 million in 2018.
- Issuance of Senior Notes due 2026, as defined below, for $394.0 million in net proceeds in 2018 in conjunction with the Delaware Asset Acquisition.

Net cash provided by (used in) financing activities includes the following for the periods indicated:

	Years Ended December 31,		
	2019	2018	$ Change
		(In thousands)	
Net borrowings on Credit Facility	$1,560,400	$175,000	$1,385,400
Repayment of Prior Credit Facility	(475,400)	—	(475,400)
Repayment of Carrizo credit facility	(853,549)	—	(853,549)
Repayment of Carrizo preferred stock	(220,399)	—	(220,399)
Issuance of 6.375% Senior Notes due 2026	—	400,000	(400,000)
Issuance of common stock	—	287,988	(287,988)
Payment of preferred stock dividends	(3,997)	(7,295)	3,298
Redemption of preferred stock	(73,017)	—	(73,017)
Payment of deferred financing costs	(22,480)	(9,430)	(13,050)
Tax withholdings related to restricted stock units	(2,195)	(1,804)	(391)
Net cash provided by (used in) financing activities	($90,637)	$844,459	($935,096)

See “Note 7 – Borrowings” of the Notes to our Consolidated Financial Statements for additional information about the Company’s debt. See “Note 11 – Stockholders’ Equity” of the Notes to our Consolidated Financial Statements for additional information about the Company’s equity offerings and the redemption of our Preferred Stock.

Senior Secured Credit Facility. Upon consummation of the Merger on December 20, 2019, the Company terminated the Sixth Amended and Restated Credit Agreement to the Credit Facility (the “Prior Credit Facility”) and entered into the credit agreement with a syndicate of lenders (the “Credit Facility”). The Credit Facility provides for interest-only payments until December 20, 2024 (subject to springing maturity dates of (i) January 14, 2023 if the 6.25% Senior Notes are outstanding at such time and (ii) July 2, 2024 if the 6.125% Senior Notes are outstanding at such time), when the Credit Facility matures and any outstanding borrowings are due. The maximum credit amount under the Credit Facility is $5.0 billion. The borrowing base under the Credit Facility is subject to regular redeterminations in the spring and fall of each year, as well as special redeterminations described in the credit agreement, which in each case may reduce the amount of the borrowing base. The Credit Facility is secured by first preferred mortgages covering the Company’s major producing properties. The capitalized terms which hare not defined in this description of the revolving credit facility shall have the meaning given to such terms in the credit agreement.

As of December 31, 2019, the borrowing base under the Credit Facility was $2.5 billion, with an elected commitment amount of $2.0 billion, and borrowings outstanding of $1.3 billion. The weighted average interest rate of our outstanding borrowings was 3.56%. The Company also had $17.7 million in letters of credit outstanding under the Credit Facility as of December 31, 2019.

Effective April 5, 2018, the Company entered into the first amendment to the Prior Credit Facility, as defined below, which (1) increased the borrowing base to $825.0 million, (2) increased the elected commitment amount to $650.0 million, (3) amended various covenants and terms to reflect current market trends, and (4) extended the maturity date to May 25, 2023.

Effective September 27, 2018, the Company entered into the second amendment to the Prior Credit Facility, which (1) increased the borrowing base to $1.1 billion, (2) increase the elected commitment amount to $850.0 million, and (3) amended various covenants and terms to reflect current market trends.

Each of the first and second amendments to the Prior Credit Facility were terminated in conjunction with the termination of the Prior Credit Facility.

See “Note 7 – Borrowings” of the Notes to our Consolidated Financial Statements for additional information.

Senior Notes

Upon consummation of the Merger, we became successor-in-interest to the indenture governing Carrizo’s 8.25% Senior Notes due 2025 (the “8.25% Senior Notes”) and the 6.25% Senior Notes due 2023 (the “6.25% Senior Notes”). Both the 8.25% Senior Notes and the 6.25% Senior Notes are guaranteed on a senior unsecured basis by our wholly-owned subsidiary, Callon Petroleum Operating Company, and may be guaranteed by certain future subsidiaries. The assumed Senior Notes are described below along with Callon’s legacy Senior Notes.

6.375% Senior Notes. On June 7, 2018, we issued $400.0 million aggregate principal amount of 6.375% Senior Notes due 2026 (the “6.375% Senior Notes”), which mature on July 1, 2026 and have interest payable semi-annually each January 1 and July 1. The net proceeds from the offering of approximately $394.0 million, after deducting initial purchasers’ discounts and estimated offering expenses, were used to fund a portion of the Delaware Asset Acquisition, described below. The 6.375% Senior Notes are guaranteed on a senior unsecured basis by our wholly-owned subsidiary, Callon Petroleum Operating Company, and may be guaranteed by certain future subsidiaries. The subsidiary guarantor is 100% owned, all of the guarantees are full and unconditional and joint and several, the parent company has no independent assets or operations and any subsidiaries of the parent company other than the subsidiary guarantor are minor.

6.125% Senior Notes. On October 3, 2016, we issued $400.0 million aggregate principal amount of 6.125% Senior Notes with a maturity date of October 1, 2024 and interest payable semi-annually each April 1 and October 1. The 6.125% Senior Notes are guaranteed on a senior unsecured basis by our wholly-owned subsidiary, Callon Petroleum Operating Company, and may be guaranteed by certain future subsidiaries. On May 19, 2017, we issued an additional $200.0 million aggregate principal amount of 6.125% Senior Notes which, with the existing $400.0 million aggregate principal amount of 6.125% Senior Notes, are treated as a single class of notes under the indenture.

8.25% Senior Notes. The 8.25% Senior Notes have an aggregate principal amount of $250.0 million, mature on July 15, 2025 and have interest payable semi-annually each January 15 and July 15. Before July 15, 2020, we may, at our option, redeem all or a portion of the 8.25% Senior Notes at 100% of the principal amount plus accrued and unpaid interest and a make-whole premium. Thereafter, we may redeem all or a portion of the 8.25% Senior Notes at redemption prices decreasing annually from 106.188% to 100% of the principal amount redeemed plus accrued and unpaid interest.

6.25% Senior Notes. The 6.25% Senior Notes have an aggregate principal amount of $650.0 million, mature on April 15, 2023 and have interest payable semi-annually each April 15 and October 15. We may redeem all or a portion of the 6.25% Senior Notes at redemption prices decreasing from 103.125% to 100% of the principal amount on April 15, 2021, plus accrued and unpaid interest.

See “Note 7 - Borrowings” of the Notes to our Consolidated Financial Statements for additional information about our Senior Notes.

Preferred Stock. Holders of the Preferred Stock were entitled to receive, when, as and if declared by the Board of Directors, out of funds legally available for the payment of dividends, cumulative cash dividends at a rate of 10% per annum of the $50.00 liquidation preference per share (equivalent to $5.00 per annum per share). Dividends were payable quarterly in arrears on the last day of each March, June, September and December when, as and if declared by the Board of Directors. Preferred Stock dividends were $4.0 million and $7.3 million for the years ended December 31, 2019 and 2018, respectively.

On June 18, 2019, we announced we had given notice for the redemption (the “Redemption”) of all outstanding shares of the Preferred Stock. On July 18, 2019 (the “Redemption Date”), the Preferred Stock were redeemed at a redemption price equal to $50.00 per share, plus an amount equal to all accrued and unpaid dividends in an amount equal to $0.24 per share, for a total redemption price of $50.24 per share or $73.0 million (the “Redemption Price”). We recognized an $8.3 million loss on the redemption due to the excess of the $73.0 million redemption price over the $64.7 million redemption date carrying value of the Preferred Stock.

After the Redemption Date, the Preferred Stock were no longer deemed outstanding, dividends on the Preferred Stock ceased to accrue, and all rights of the holders with respect to such Preferred Stock were terminated, except the right of the holders to receive the Redemption Price, without interest.

See “Note 11 - Stockholders’ Equity” of the Notes to our Consolidated Financial Statements for additional discussion.

2020 Capital Plan and Outlook

Our 2020 Capital Budget has been established at $975.0 million, which includes running an average of eight to nine drilling rig sand an average of three completion crews. Approximately 10-15% of the 2020 Capital Budget is comprised of infrastructure and facilities capital. As part of our 2020 operated horizontal drilling program, we expect to drill approximately 165 gross operated wells and complete approximately 160 gross operated wells. We currently expect to direct the majority of our 2020 Capital Budget towards opportunities in the Permian Basin. Additionally, we may consider divesting certain properties or assets that are not part of our core business or are no longer deemed essential to our future growth, provided we are able to divest such assets on terms that are acceptable to us.

Our revenues, earnings, liquidity and ability to grow are substantially dependent on the prices we receive for, and our ability to develop our proved reserves. We believe the long-term outlook for our business is favorable due to our resource base, low cost structure, financial strength, risk management, and disciplined investment of capital. We monitor current and expected market conditions, including the commodity price environment, and our liquidity needs and may adjust our capital investment plan accordingly.

Contractual Obligations

The following table includes our current contractual obligations and purchase commitments as of December 31, 2019:

	Payments due by Period				
	< 1 Year	Years 2 - 3	Years 4 - 5	> 5 Years	Total
			(In thousands)		
6.25% Senior Notes (1)	$—	$—	$650,000	$—	$650,000
6.125% Senior Notes (1)	—	—	600,000	—	600,000
8.25% Senior Notes (1)	—	—	—	250,000	250,000
6.375% Senior Notes (1)	—	—	—	400,000	400,000
Credit Facility (2)	—	—	1,285,000	—	1,285,000
Interest expense and other fees related to debt commitments (3)	172,821	345,642	283,218	71,625	873,306
Drilling rig leases (4)	33,441	3,249	—	—	36,690
Operating leases	12,423	12,762	8,319	17,902	51,406
Delivery commitments (5)	9,563	24,417	23,970	39,298	97,248
Produced water disposal commitments (6)	14,947	26,901	5,957	1,840	49,645
Asset retirement obligations (7)	468	314	565	48,386	49,733
Other commitments	1,240	844	159	—	2,243
Total contractual obligations	$244,903	$414,129	$2,857,188	$829,051	$4,345,271

(1) Includes the outstanding principal amount only.

(2) The Credit Facility has a maturity date of December 20, 2024, subject to springing maturity dates as discussed above. See "Note 7 – Borrowings" of the Notes to our Consolidated Financial Statements for additional information.

(3) Includes estimated cash payments on the 6.25% Senior Notes, 6.125% Senior Notes, 8.25% Senior Notes, 6.375% Senior Notes, the Credit Facility and commitment fees calculated based on the unused portion of lender commitments as of December 31, 2019, at the applicable commitment fee rate.

(4) Drilling rig leases represent future minimum expenditure commitments for drilling rig services under contracts to which the Company was a party on December 31, 2019. The value in the table represents the gross amount that we are committed to pay. However, we will record our proportionate share based on our working interest in our consolidated financial statements as incurred. See "Note 17 – Commitments and Contingencies" of the Notes to our Consolidated Financial Statements for additional information related to the Company's drilling rig leases.

(5) Delivery commitments represent contractual obligations we have entered into for certain gathering, processing and transportation service agreements which require minimum volumes of natural gas to be delivered. The amounts in the table above reflect the aggregate undiscounted deficiency fees assuming no delivery of any natural gas.

(6) Produced water disposal commitments represent contractual obligations we have entered into for certain service agreements which require minimum volumes of produced water to be delivered. The amounts in the table above reflect the aggregate undiscounted deficiency fees assuming no delivery of any produced water.

(7) Amounts represent our estimates of future asset retirement obligations. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment. See "Note 14 – Asset Retirement Obligations" of the Notes to our Consolidated Financial Statements for additional information.

Other commitments

In July 2019, the Company executed a crude oil sales contract that provides dedicated capacity on a new pipeline system that originates in Midland County, Texas and will have delivery points in several locations along the Gulf Coast. We will have a long-term 5,000 Bbls per day commitment for the term of the agreement and will apply applicable tariff rates to those quantities. Barrels may include volumes produced by us and other third-party working, royalty, and overriding royalty interest owners whose volumes we market on their behalf.

In June 2019, the Company executed a firm transportation agreement for dedicated capacity on a new pipeline system that originates in Midland, Texas and terminates in Houston, Texas. Subject to completion of the new pipeline system, which will have delivery points in several locations along the Gulf Coast, we will have a long-term commitment that will apply applicable tariff rates to our quantities committed that average 10,000 Bbls per day for the term of the agreement. Barrels may be transported to multiple delivery points along the Gulf Coast and may include volumes produced by us and other third-party working, royalty, and overriding royalty interest owners whose volumes we market on their behalf.

In January 2019, the Company executed a crude oil sales contract that provides further dedicated capacity on several pipeline systems that will connect with a regional gathering system which currently transports oil volumes under long-term agreements from our properties in Howard and Ward counties, Texas and will have delivery points in several locations along the Gulf Coast, providing the Company with the potential benefit of access to an international weighted average sales price. We will have a long-term 10,000 Bbls per day commitment for the term of the agreement, and may include volumes produced by us and other third-party working, royalty, and overriding royalty interest owners whose volumes we market on their behalf.

In August 2018, the Company executed a firm transportation agreement for dedicated capacity on a new pipeline system that will connect with a regional gathering system which currently transports oil volumes under long-term agreements from our properties in Howard and Ward counties, Texas to multiple marketing points in the Permian Basin. Subject to completion of the new pipeline system, which will have delivery points in several locations along the Gulf Coast, we will have a long-term commitment that will apply applicable tariff rates to our 15,000 Bbls per day commitment for the term of the agreement. Barrels may be transported to multiple delivery points along the Gulf Coast and may include volumes produced by us and other third-party working, royalty, and overriding royalty interest owners whose volumes we market on their behalf.

In March 2018, the Company entered into a contract for dedicated fracturing and pump down perforating crews, which was effective on April 16, 2018 for a two-year period. The agreement was amended effective October 16, 2018 to reflect updated market conditions and to extend the contract expiration date to December 31, 2021.

Summary of Critical Accounting Policies

The following summarizes our critical accounting policies. See a complete list of significant accounting policies in "Note 2 – Summary of Significant Accounting Policies" of the Notes to our Consolidated Financial Statements.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make judgments affecting estimates and assumptions for reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Estimates of proved oil and gas reserves are used in calculating DD&A of proved oil and natural gas property costs, the present value of estimated future net revenues included in the full cost ceiling test, estimates of future taxable income used in assessing the realizability of deferred tax assets, and the estimated timing of cash outflows underlying asset retirement obligations. There are numerous uncertainties inherent in the estimation of proved oil and gas reserves and in the projection of future rates of production and the timing of development expenditures. Other significant estimates are involved in determining asset retirement obligations, acquisition date fair values of assets acquired and liabilities assumed, impairments of unevaluated leasehold costs, fair values of commodity derivative assets and liabilities, fair values of contingent consideration arrangements, grant date fair value of stock-based awards, and contingency, litigation, and environmental liabilities. Actual results could differ from those estimates.

Oil and natural gas properties

Oil and natural gas properties are accounted for using the full cost method of accounting under which all productive and nonproductive costs directly associated with property acquisition, exploration and development activities are capitalized as oil and gas properties. The internal cost of employee compensation and benefits, including stock-based compensation, directly associated with acquisition, exploration and development activities are capitalized to either evaluated or unevaluated oil and gas properties based on the type of activity. Internal costs related to production and similar activities are expensed as incurred.

Proceeds from the sale or disposition of evaluated and unevaluated oil and gas properties are accounted for as a reduction of evaluated oil and gas property costs, unless the sale significantly alters the relationship between capitalized costs and proved reserves in which case a gain or loss is recognized. For the years ended December 31, 2019 and 2018, we did not have any sales of oil and gas properties that significantly altered such relationship.

Capitalized oil and gas property costs within a cost center are amortized on an equivalent unit-of-production method, converting natural gas to barrels of oil equivalent at the ratio of six thousand cubic feet of gas to one barrel of oil, which represents their approximate relative energy content. The equivalent unit-of-production amortization rate is computed on a quarterly basis by dividing current quarter production by proved oil and gas reserves at the beginning of the quarter then applying such amortization rate to evaluated oil and gas property costs, which includes estimated asset retirement costs, less accumulated amortization, plus estimated future expenditures (based on current costs) to be incurred in developing proved reserves, net of estimated salvage values.

Excluded from this amortization are costs associated with unevaluated leasehold and seismic costs associated with specific unevaluated properties and related capitalized interest. Unevaluated property costs are transferred to evaluated property costs at such time as wells are completed on the properties or we determine that these costs have been impaired. We assesses properties on an individual basis or as a group and considers the following factors, among others, to determine if these costs have been impaired: exploration program and intent to drill, remaining lease term, and the assignment of proved reserves. Geological and geophysical costs not associated with specific prospects are recorded to evaluated oil and gas property costs as incurred. The amount of interest costs capitalized is determined on a quarterly basis based on the average balance of unproved properties and the weighted average interest rate of outstanding borrowings. Capitalized interest cannot exceed gross interest expense.

Write-down of Evaluated Properties

At the end of each quarter, the net book value of oil and gas properties, less related deferred income taxes, are limited to the "cost center ceiling" equal to (i) the sum of (a) the present value of estimated future net revenues from proved oil and gas reserves, less estimated future expenditures to be incurred in developing and producing the proved reserves computed using a discount factor of 10%, (b) the costs of unevaluated properties not being amortized, and (c) the lower of cost or estimated fair value of unevaluated properties included in the costs being amortized; less (ii) related income tax effects. Any excess of the net book value of oil and gas properties, less related deferred income taxes, over the cost center ceiling is recognized as an write-down of evaluated oil and gas properties. A write-down recognized in one period may not be reversed in a subsequent period even if higher commodity prices in the future result in a cost center ceiling in excess of the net book value of oil and gas properties, less related deferred income taxes.

The estimated future net revenues used in the cost center ceiling are calculated using the 12-Month Average Realized Price, held flat for the life of the production, except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts. Prices do not include the impact of commodity derivative instruments as we elected not to meet the criteria to qualify for hedge accounting treatment.

Details of the 12-Month Average Realized Price of crude oil for the years ended December 31, 2019 and 2018 are summarized in the table below:

	Years Ended December 31,	
	2019	2018
Write-down of evaluated oil and natural gas properties (In thousands)	$—	$—
Crude Oil 12-Month Average Realized Price ($/Bbl) - Beginning of period	$58.40	$49.48
Crude Oil 12-Month Average Realized Price ($/Bbl) - End of period	$53.90	$58.40
Crude Oil 12-Month Average Realized Price percentage increase (decrease)	(8%)	18%

The table below presents various pricing scenarios to demonstrate the sensitivity of our December 31, 2019 cost center ceiling to changes in 12-month average benchmark crude oil and natural gas prices underlying the 12-Month Average Realized Prices. The sensitivity analysis is as of December 31, 2019 and, accordingly, does not consider drilling and completion activity, acquisitions or dispositions of oil and gas properties, production, changes in crude oil and natural gas prices, and changes in development and operating costs occurring subsequent to December 31, 2019 that may require revisions to estimates of proved reserves. See also Part I, "Item 1A. Risk Factors—If oil and natural gas prices remain depressed for extended periods of time, we could be required to make significant downward adjustments to the carrying value of our oil and natural gas properties."

	12-Month Average Realized Prices		Excess of cost center ceiling over net book value, less related deferred income taxes	Increase (decrease) of cost center ceiling over net book value, less related deferred income taxes
Full Cost Pool Scenarios	**Crude Oil ($/Bbl)**	**Natural Gas ($/Mcf)**	**(In millions)**	**(In millions)**
December 31, 2019 Actual	$53.90	$1.55	$631	
Crude Oil and Natural Gas Price Sensitivity				
Crude Oil and Natural Gas +10%	$59.47	$1.85	$1,456	$825
Crude Oil and Natural Gas -10%	$48.33	$1.25	($369)	($1,000)
Crude Oil Price Sensitivity				
Crude Oil +10%	$59.47	$1.55	$1,378	$747
Crude Oil -10%	$48.33	$1.55	($270)	($901)
Natural Gas Price Sensitivity				
Natural Gas +10%	$53.90	$1.85	$702	$71
Natural Gas -10%	$53.90	$1.25	$546	($85)

We estimate that the first quarter of 2020 cost center ceiling will exceed the net book value, less related deferred income taxes, resulting in no write-down of evaluate oil and gas properties. This estimate of the first quarter of 2020 cost center ceiling test is based on an estimated 12-Month Average Realized Price of crude oil of $56.09 per barrel as of March 31, 2020, which is based on the average realized price for sales of crude oil on the first calendar day of each month for the first 11 months and an estimate for the twelfth month based on a quoted forward price.

Both of these estimates assume that all other inputs and assumptions are as of December 31, 2019, other than the price of crude oil, and remain unchanged. As such, drilling and completion activity, acquisitions or dispositions of oil and gas properties, production, and changes in development and operating costs occurring subsequent to December 31, 2019 may require revisions to estimates of proved reserves, which would impact the calculation of the cost center ceiling.

Estimating reserves and present value of estimated future net cash flows

Estimates of quantities of proved oil and natural gas reserves, including the discounted present value of estimated future net cash flows from such reserves at the end of each quarter, are based on numerous assumptions, which are likely to change over time. These assumptions include:

- the prices at which the Company can sell its production in the future. Oil, natural gas, and NGL prices are volatile, but we are required to assume that they remain constant, using the 12-Month Average Realized Price. In general, higher oil, natural gas, and NGL prices will increase quantities of estimated proved reserves and the present value of estimated future net cash flows from such reserves, while lower prices will decrease these amounts; and

- the costs to develop and produce the Company's reserves and the costs to dismantle its production facilities when reserves are depleted. These costs are likely to change over time, but we are required to assume that they remain constant. Increases in costs will reduce estimated proved reserves and the present value of estimated future net cash flows, while decreases in costs will increase such amounts.

Changes in these prices and/or costs will affect the present value of estimated future net cash flows more than the estimated proved reserves for the Company's properties that have relatively short productive lives. If oil, natural gas, and NGL prices remain at current levels or decline further, it will have a negative impact on the present value of estimated future net cash flows and the estimated quantities of proved reserves.

In addition, the process of estimating proved oil and natural gas reserves requires that the Company's independent and internal reserve engineers exercise judgment based on available geological, geophysical and technical information. We have described the risks associated with reserve estimation and the volatility of oil and natural gas prices under Part I, "Item 1A. Risk Factors."

Asset retirement obligations

We record an estimate of the fair value of liabilities for obligations associated with plugging and abandoning oil and gas wells, removing production equipment and facilities and restoring the surface of the land in accordance with the terms of oil and gas leases and applicable local, state and federal laws. Estimates involved in determining asset retirement obligations include the future plugging and abandonment costs of wells and related facilities, the ultimate productive life of the properties, a credit-adjusted risk-free discount rate and an inflation factor in order to determine the present value of the asset retirement obligation. The present value of the asset retirement obligations is accreted each period and the increase to the obligation is reported in "Depreciation, depletion and amortization" in the consolidated statements of operations. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation liability, a corresponding adjustment is made to evaluated properties in the consolidated balance sheets. See "Note 14 - Asset Retirement Obligations" of the Notes to our Consolidated Financial Statements for additional information.

Estimating the future plugging and abandonment costs of wells and related facilities requires management to make estimates and judgments because most of the obligations are many years in the future and asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

Derivative Instruments

To manage oil and natural gas price risk on a portion of our planned future production, we have historically utilized commodity derivative instruments (including collars, swaps, put and call options and other structures) on approximately 40% to 60% of our projected production volumes in any given year. We do not use these instruments for speculative purposes. Settlements of derivative contracts are generally based on the difference between the contract price and prices specified in the derivative instrument and a NYMEX price or other futures index price.

Our derivative positions are carried at their fair value on the balance sheet with changes in fair value recorded through earnings. The estimated fair value of our derivative contracts is based upon current forward market prices on NYMEX and in the case of collars and floors, the time value of options. For additional information regarding derivatives and their fair values, see "Note 8 - Derivative Instruments and Hedging Activities" and "Note 9 - Fair Value Measurements" of the Notes to our Consolidated Financial Statements and "Part II, Item 7A. Quantitative and Qualitative Disclosures About Market Risk - Commodity Price Risk".

Income taxes

The amount of income taxes recorded requires interpretations of complex rules and regulations of federal and state tax jurisdictions. We recognize current tax expense based on estimated taxable income for the current period and the applicable statutory tax rates. We routinely assess potential uncertain tax positions and, if required, estimate and establish accruals for such amounts. We have recognized deferred tax assets and liabilities for temporary differences, operating losses and other tax carryforwards. We routinely assess our deferred tax assets and reduce such assets by a valuation allowance if we deem it is more likely than not that some portion or all of the deferred tax assets will not be realized. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and natural gas prices). The Company had no valuation allowance as of December 31, 2019 and 2018. See "Note 12 - Income Taxes" of the Notes to our Consolidated Financial Statements for additional information regarding income taxes.

Accounting Standards Updates

See "Note 2 - Summary of Significant Accounting Policies" of the Notes to our Consolidated Financial Statements for information discussion of recent accounting pronouncements issued by the Financial Accounting Standards Board.

Off-balance Sheet Arrangements

We had no off-balance sheet arrangements as of December 31, 2019.

ITEM 7A. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to a variety of market risks including commodity price risk, interest rate risk and counterparty and customer credit risk. We mitigate these risks through a program of risk management including the use of commodity derivative instruments.

Commodity price risk

The Company's revenues are derived from the sale of its oil and natural gas production. The prices for oil and natural gas remain volatile and sometimes experience large fluctuations as a result of relatively small changes in supply, weather conditions, economic conditions and government actions. From time to time, the Company enters into derivative financial instruments to manage oil and natural gas price risk, related both to NYMEX benchmark prices and regional basis differentials. The total volumes which we hedge through use of our derivative instruments varies from period to period; however, generally our objective is to hedge approximately 40% to 60% of our anticipated internally forecast production for the next 12 to 24 months, subject to the covenants under our Credit Facility. Our hedge policies and objectives may change significantly with movements in commodities prices or futures prices.

As of December 31, 2019, for the full year of 2020, the Company had 18,017,900 Bbls of fixed price oil hedges across NYMEX WTI, ICE Brent and Argus WTI-Houston benchmarks. The Company also had 8,476,700 Bbls of WTI Midland-Cushing oil basis hedges and 1,439,205 Bbls of WTI Houston-Cushing oil basis hedges. Additionally, for the full year of 2020, the Company had 7,320,000 MMBtus of fixed price NYMEX natural gas hedges and 21,596,000 MMBtus of Waha natural gas basis hedges. See "Note 8 - Derivative Instruments and Hedging Activities" of the Notes to our Consolidated Financial Statements for a description of the Company's outstanding derivative contracts as of December 31, 2019.

The Company may utilize fixed price swaps, which reduce the Company's exposure to decreases in commodity prices and limit the benefit the Company might otherwise have received from any increases in commodity prices. Swap contracts may also be enhanced by the simultaneous sale of call or put options to effectively increase the effective swap price as a result of the receipt of premiums from the option sales.

The Company may utilize price collars to reduce the risk of changes in oil and natural gas prices. Under these arrangements, no payments are due by either party as long as the applicable market price is above the floor price (purchased put option) and below the ceiling price (sold call option) set in the collar. If the price falls below the floor, the counter-party to the collar pays the difference to the Company, and if the price rises above the ceiling, the counterparty receives the difference from the Company. Additionally, the Company may sell put (or call) options at a price lower than the floor price (or higher than the ceiling price) in conjunction with a collar (three-way collar) and use the proceeds to increase either or both the floor or ceiling prices. In a three-way collar, to the extent that realized prices are below the floor price of the sold put option (or above the ceiling price of the sold call option), the Company's net realized benefit from the three-way collar will be reduced on a dollar-for-dollar basis.

The Company may purchase put and call options, which reduce the Company's exposure to decreases in oil and natural gas prices while allowing realization of the full benefit from any increases in oil and natural gas prices. If the price falls below the floor, the counterparty pays the difference to the Company.

The Company enters into these various agreements from time to time to reduce the effects of volatile oil and natural gas prices and does not enter into derivative transactions for speculative purposes. Presently, none of the Company's derivative positions are designated as hedges for accounting purposes.

Interest rate risk

The Company is subject to market risk exposure related to changes in interest rates on our indebtedness under our Credit Facility. As of December 31, 2019, the Company had $1.3 billion outstanding under the Credit Facility with a weighted average interest rate of 3.56%. An increase or decrease of 1.00% in the interest rate would have a corresponding increase or decrease in our annual net income of approximately $12.9 million based on the balance outstanding at December 31, 2019. See "Note 7 - Borrowings" of the Notes to our Consolidated Financial Statements for more information on the Company's interest rates on our Credit Facility.

Counterparty and customer credit risk

The Company's principal exposures to credit risk are through receivables from the sale of our oil and natural gas production, joint interest receivables and receivables resulting from derivative financial contracts.

The Company markets its oil and natural gas production to energy marketing companies. We are subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. For the year ended December 31, 2019, four purchasers accounted for more than 10% of our revenue: Rio Energy International, Inc. (26%); Enterprise Crude Oil, LLC (19%); Plains Marketing, L.P. (15%); and Shell Trading Company (10%). The inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. In order to mitigate potential exposure to credit risk, we may require from time to time for our customers to provide financial security. At December 31, 2019 our total receivables from the sale of our oil and natural gas production were approximately $165.3 million.

Joint interest receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we have or intend to drill. We have little ability to control whether these entities will participate in our wells. At December 31, 2019, our joint interest receivables were approximately $42.5 million.

Our oil and natural gas commodity derivative arrangements expose us to credit risk in the event of nonperformance by counterparties. Most of the counterparties on our commodity derivative instruments currently in place are lenders under our Credit Facility. We are likely to enter into additional commodity derivative instruments with these or other lenders under our Credit Facility, representing institutions with investment grade ratings. We have existing International Swap Dealers Association Master Agreements ("ISDA Agreements") with our commodity derivative counterparties. The terms of the ISDA Agreements provide us and the counterparties with rights of offset upon the occurrence of defined acts of default by either us or a counterparty to a commodity derivative, whereby the party not in default may offset all commodity derivative liabilities owed to the defaulting party against all commodity derivative asset receivables from the defaulting party. At December 31, 2019, we had a net commodity derivative liability position of $24.8 million.

ITEM 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Callon Petroleum Company

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Callon Petroleum Company (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2019 and 2018, the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, 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, 2019, 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 28, 2020 expressed an unqualified opinion.

Change in accounting principle

As discussed in Note 2 to the consolidated financial statements, the Company has changed its method of accounting for leases in the year ended December 31, 2019 due to the adoption of FASB Accounting Standards Codification Topic 842, *Leases*.

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.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

<u>Depletion expense and impairment of oil and gas properties impacted by the Company's estimation of proved reserves</u>

As described further in Note 2 to the financial statements, the Company accounts for its oil and gas properties using the full cost method of accounting which requires management to make estimates of proved reserve volumes and future net revenues to record depletion expense and assess its oil and gas properties for potential impairment. To estimate the volume of proved reserves and future net revenue, management makes significant estimates and assumptions including forecasting the production decline rate of producing properties and forecasting the timing and volume of production associated with the Company's development plan for proved undeveloped properties. In addition, the estimation of proved reserves is also impacted by management's judgments and estimates regarding the financial performance of wells associated with proved reserves to determine if wells are expected with reasonable certainty to be economical under the appropriate pricing assumptions required in the estimation of depletion expense and potential impairment assessment. We identified the estimation of proved reserves of oil and gas properties as a critical audit matter.

The principal consideration for our determination that the estimation of proved reserves is a critical audit matter is that changes in certain inputs and assumptions, which require a high degree of subjectivity, necessary to estimate the volume and future net revenues of the Company's proved reserves could have a significant impact on the measurement of depletion expense and potential impairment. In turn, auditing those inputs and assumptions required subjective and complex auditor judgment.

Our audit procedures related to the estimation of proved reserves included the following, among others.

- We tested the design and operating effectiveness of controls relating to management's estimation of proved reserves for the purpose of estimating depletion expense and assessing the Company's oil and gas properties for potential impairment.
- We evaluated the independence, objectivity, and professional qualifications of the Company's reserve engineers, made inquiries of those specialists regarding the process followed and judgments made to estimate the Company's proved reserve volumes, and read the reserve report prepared by the Company's specialists.
- To the extent key inputs and assumptions used to determine proved reserve volumes and other cash flow inputs and assumptions are derived from the Company's accounting records, including, but not limited to: historical pricing differentials, operating costs, estimated capital costs, and ownership interests, we tested management's process for determining the assumptions, including examining the underlying support on a sample basis. Specifically, our audit procedures involved testing management's assumptions by performing the following:
    - Compared the estimated pricing differentials used in the reserve report to realized prices related to revenue transactions recorded in the current year and examined contractual support for the pricing differentials;
    - Tested models used to estimate the future operating costs in the reserve report and compared amounts to historical operating costs;
    - Evaluated the method used to determine the future capital costs and compared estimated future capital expenditures used in the reserve report to amounts expended for recently drilled and completed wells;
    - Tested the working and net revenue interests used in the reserve report by inspecting land and division order records;
    - Evaluated the Company's evidence supporting the amount of proved undeveloped properties reflected in the reserve report by examining historical conversion rates and support for the Company's ability to fund and intent to develop the proved undeveloped properties; and
    - Applied analytical procedures to the reserve report forecasted production by comparing to historical actual results, and to the prior year reserve report.

<u>Fair value of oil and gas properties acquired impacted by the Company's estimation of proved reserves</u>

As described in Note 4 to the financial statements, the Company acquired Carrizo Oil & Gas, Inc. which requires management to make estimates of fair values associated with proved reserve volumes. To estimate the volume of proved reserves and future net revenue, management makes significant estimates and assumptions including forecasting the production decline rate of producing properties and forecasting the timing and volume of production associated with the Company's development plan for proved undeveloped properties. In addition, the estimation of proved reserves is also impacted by management's judgments and estimates regarding the financial performance of wells associated with proved reserves to determine if wells are expected with reasonable certainty to be economical under the appropriate pricing assumptions required in the estimation of fair value. We identified the estimation of proved reserves of oil and gas properties acquired as a critical audit matter.

The principal consideration for our determination that the estimation of proved reserves is a critical audit matter is that changes in certain inputs and assumptions, which require a high degree of subjectivity, necessary to estimate the volume and future net revenues of the Company's proved reserves could have a significant impact on the measurement of fair value. In turn, auditing those inputs and assumptions required subjective and complex auditor judgment.

Our audit procedures related to the estimation of proved reserves included the following, among others.

- We tested the design and operating effectiveness of controls relating to management's estimation of proved reserves for the purpose of estimating the fair value assigned to proved properties.
- We evaluated the independence, objectivity, and professional qualifications of the Company's reserve engineers, made inquiries of those specialists regarding the process followed and judgments made to estimate the Company's proved reserve volumes, and read the reserve report prepared by those specialists.
- We evaluated the independence, objectivity, and professional qualifications of the Company's valuation specialists, made inquiries of those valuation specialists regarding the process followed and judgments made to determine the fair value associated with proved reserve volumes, and read the valuation report prepared by the external specialists.

- To the extent key sensitive inputs and assumptions used to determine proved reserve volumes and other cash flow inputs and assumptions are derived from the Company's accounting records or other third party information, including, but not limited to: historical pricing differentials, operating costs, estimated capital costs, and ownership interests, we tested management's process for determining the assumptions, including examining the underlying support on a sample basis. Specifically, our audit procedures involved testing management's assumptions by performing the following:
  - Compared the estimated pricing differentials used in the reserve report to realized prices related to revenue transactions recorded in the current year and examined contractual support for the pricing differentials;
  - Tested models used to estimate the future operating costs in the acquisition reserve report and compared amounts to historical operating costs;
  - Evaluated the method used to determine the future capital costs and compared estimated future capital expenditures used in the valuation reserve report to amounts expended for recently drilled and completed wells;
  - Evaluated the working and net revenue interests used in the reserve report by inspecting land and division order records;
  - Evaluated the risk adjustments applied to proved reserve volumes by comparing against industry accepted factors;
  - Evaluated the Company's evidence supporting the amount of proved undeveloped properties reflected in the reserve report by examining historical conversion rates and support for the Company's ability to fund and intent to develop the proved undeveloped properties; and
  - Applied analytical procedures to the reserve report forecasted production by comparing to historical actual results, and to the prior year reserve report.

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2016.

Houston, Texas

February 28, 2020

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Callon Petroleum Company

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of Callon Petroleum Company (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2019, 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, 2019, 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, 2019, and our report dated February 28, 2020 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 Carrizo Oil & Gas, Inc., a wholly-owned subsidiary, whose financial statements reflect total assets and revenues constituting 43 and 4 percent, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2019. As indicated in Management's Report, Carrizo Oil & Gas, Inc. was acquired during 2019. Management's assertion on the effectiveness of the Company's internal control over financial reporting excluded internal control over financial reporting of Carrizo Oil & Gas, 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

Houston, Texas
February 28, 2020

Callon Petroleum Company
Consolidated Balance Sheets
(In thousands, except par and share data)

	December 31,	
	2019	**2018**
ASSETS		
Current assets:		
Cash and cash equivalents	$13,341	$16,051
Accounts receivable, net	209,463	131,720
Fair value of derivatives	26,056	65,114
Other current assets	19,814	9,740
Total current assets	268,674	222,625
Oil and natural gas properties, full cost accounting method:		
Evaluated properties, net	4,682,994	2,314,345
Unevaluated properties	1,986,124	1,404,513
Total oil and natural gas properties, net	6,669,118	3,718,858
Operating lease right-of-use assets	63,908	—
Other property and equipment, net	35,253	21,901
Deferred tax asset	115,720	—
Deferred financing costs	22,233	6,087
Fair value of derivatives	9,216	—
Other assets, net	10,716	9,702
Total assets	$7,194,838	$3,979,173
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$511,622	$285,849
Operating lease liabilities	42,858	—
Fair value of derivatives	71,197	10,480
Other current liabilities	26,570	18,587
Total current liabilities	652,247	314,916
Long-term debt	3,186,109	1,189,473
Operating lease liabilities	37,088	—
Asset retirement obligations	48,860	10,405
Deferred tax liability	—	9,564
Fair value of derivatives	32,695	7,440
Other long-term liabilities	14,531	2,167
Total liabilities	3,971,530	1,533,965
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, series A cumulative, $0.01 par value and $50.00 liquidation preference, 2,500,000 shares authorized: 0 and 1,458,948 shares outstanding, respectively	—	15
Common stock, $0.01 par value, 525,000,000 and 300,000,000 shares authorized, respective; 396,600,022 and 227,582,575 shares outstanding, respectively	3,966	2,276
Capital in excess of par	3,198,076	2,477,278
Retained earnings (Accumulated deficit)	21,266	(34,361)
Total stockholders' equity	3,223,308	2,445,208
Total liabilities and stockholders' equity	$7,194,838	$3,979,173

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

Callon Petroleum Company
Consolidated Statements of Operations
(In thousands, except per share data)

	For the Year Ended December 31,		
	2019	**2018**	**2017**
Operating Revenues:			
Oil	$633,107	$530,898	$322,374
Natural gas	36,390	56,726	44,100
Natural gas liquids	2,075	—	—
Total operating revenues	671,572	587,624	366,474
Operating Expenses:			
Lease operating	91,827	69,180	49,907
Production taxes	42,651	35,755	22,396
Depreciation, depletion and amortization	240,642	182,783	116,391
General and administrative	45,331	35,293	27,067
Merger and integration expenses	74,363	—	—
Settled share-based awards	3,024	—	6,351
Other operating expense	1,076	5,083	2,916
Total operating expenses	498,914	328,094	225,028
Income From Operations	172,658	259,530	141,446
Other (Income) Expenses:			
Interest expense, net of capitalized amounts	2,907	2,500	2,159
(Gain) loss on derivative contracts	62,109	(48,544)	18,901
Loss on extinguishment of debt	4,881	—	—
Other income	(468)	(2,896)	(1,311)
Total other (income) expense	69,429	(48,940)	19,749
Income Before Income Taxes	103,229	308,470	121,697
Income tax expense	35,301	8,110	1,273
Net Income	$67,928	$300,360	$120,424
Preferred stock dividends	(3,997)	(7,295)	(7,295)
Loss on redemption of preferred stock	(8,304)	—	—
Income Available to Common Stockholders	$55,627	$293,065	$113,129
Income Available to Common Stockholders Per Common Share:			
Basic	$0.24	$1.35	$0.56
Diluted	$0.24	$1.35	$0.56
Weighted Average Common Shares Outstanding:			
Basic	233,140	216,941	201,526
Diluted	233,550	217,596	202,102

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

Callon Petroleum Company
Consolidated Statements of Stockholders' Equity
(In thousands, except share amounts)

	Preferred Stock		Common Stock		Capital in Excess of Par	Retained Earnings (Accumulated Deficit)	Total Stockholders' Equity
	Shares	$	Shares	$			
Balance at 12/31/2016	1,459	$15	201,041	$2,010	$2,171,514	($440,137)	$1,733,402
Net income	—	—	—	—	—	120,424	120,424
Shares issued pursuant to employee benefit plans	—	—	26	—	311	—	311
Restricted stock	—	—	769	8	9,098	—	9,106
Common stock issued	—	—	—	—	18	—	18
Impact of forfeiture estimate	—	—	—	—	418	(418)	—
Preferred stock dividend	—	—	—	—	—	(7,295)	(7,295)
Balance at 12/31/2017	1,459	$15	201,836	$2,018	$2,181,359	($327,426)	$1,855,966
Net income	—	—	—	—	—	300,360	300,360
Shares issued pursuant to employee benefit plans	—	—	45	—	533	—	533
Restricted stock	—	—	402	5	7,651	—	7,656
Common stock issued	—	—	25,300	253	287,735	—	287,988
Preferred stock dividend	—	—	—	—	—	(7,295)	(7,295)
Balance at 12/31/2018	1,459	$15	227,583	$2,276	$2,477,278	($34,361)	$2,445,208
Net income	—	—	—	—	—	67,928	67,928
Shares issued pursuant to employee benefit plans	—	—	24	—	154	—	154
Restricted stock	—	—	779	8	11,622	—	11,630
Common stock issued for Carrizo Acquisition	—	—	168,214	1,682	763,691	—	765,373
Common stock warrants reissued for Carrizo Acquisition	—	—	—	—	10,029	—	10,029
Preferred stock dividend	—	—	—	—	—	(3,997)	(3,997)
Preferred stock redemption	(1,459)	(15)	—	—	(64,698)	—	(64,713)
Loss on redemption of preferred stock	—	—	—	—	—	(8,304)	(8,304)
Balance at 12/31/2019	—	$—	396,600	$3,966	$3,198,076	$21,266	$3,223,308

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

Callon Petroleum Company
Consolidated Statements of Cash Flows
(In thousands)

	Years Ended December 31,		
	2019	2018	2017
Cash flows from operating activities:			
Net income	$67,928	$300,360	$120,424
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	245,936	185,605	118,728
Amortization of non-cash debt related items	2,907	2,483	2,150
Deferred income tax expense	35,301	8,110	1,273
(Gain) loss on derivative contracts	62,109	(48,544)	18,901
Cash paid for commodity derivative settlements, net	(3,789)	(27,272)	(8,472)
(Gain) loss on sale of other property and equipment	(90)	(144)	62
Non-cash loss on early extinguishment of debt	4,881	—	—
Non-cash expense related to equity share-based awards	9,767	6,289	8,254
Change in the fair value of liability share-based awards	1,624	375	3,288
Payments to settle asset retirement obligations	(4,148)	(1,469)	(2,047)
Payments for cash-settled restricted stock unit awards	(1,425)	(4,990)	(13,173)
Changes in current assets and liabilities:			
Accounts receivable	(35,071)	(17,351)	(44,495)
Other current assets	(4,166)	(7,601)	108
Current liabilities	86,438	74,311	30,947
Other	8,114	(2,508)	(6,057)
Net cash provided by operating activities	476,316	467,654	229,891
Cash flows from investing activities:			
Capital expenditures	(640,540)	(611,173)	(419,839)
Acquisitions	(42,266)	(718,793)	(718,456)
Acquisition deposit	—	—	45,238
Proceeds from sales of assets	294,417	9,009	20,525
Additions to other assets	—	(3,100)	—
Net cash used in investing activities	(388,389)	(1,324,057)	(1,072,532)
Cash flows from financing activities:			
Borrowings on senior secured revolving credit facility	2,455,900	500,000	25,000
Payments on senior secured revolving credit facility	(895,500)	(325,000)	—
Payment to terminate Prior Credit Facility	(475,400)	—	—
Repayment of Carrizo's senior secured revolving credit facility	(853,549)	—	—
Repayment of Carrizo's preferred stock	(220,399)	—	—
Issuance of 6.125% Senior Notes due 2024	—	—	200,000
Premium on the issuance of 6.125% Senior Notes due 2024	—	—	8,250
Issuance of 6.375% Senior Notes due 2026	—	400,000	—
Issuance of common stock	—	287,988	—
Payment of preferred stock dividends	(3,997)	(7,295)	(7,295)
Payment of deferred financing costs	(22,480)	(9,430)	(7,194)
Tax withholdings related to restricted stock units	(2,195)	(1,804)	(1,118)
Redemption of preferred stock	(73,017)	—	—
Net cash provided by (used in) financing activities	(90,637)	844,459	217,643
Net change in cash and cash equivalents	(2,710)	(11,944)	(624,998)
Balance, beginning of period	16,051	27,995	652,993
Balance, end of period	$13,341	$16,051	$27,995

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

INDEX TO THE NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 – Description of Business

Callon Petroleum Company is an independent oil and natural gas company established in 1950. The Company was incorporated under the laws of the state of Delaware in 1994 and succeeded to the business of a publicly traded limited partnership, a joint venture with a consortium of European investors and an independent energy company. As used herein, the "Company," "Callon," "we," "us," and "our" refer to Callon Petroleum Company and its predecessors and subsidiaries unless the context requires otherwise.

Callon is an independent oil and natural gas company focused on the acquisition, exploration and development of high-quality assets in the leading oil plays of South and West Texas. The Company's activities are primarily focused on horizontal development in the Midland and Delaware Basins, both of which are part of the larger Permian Basin in West Texas. In 2019, through its acquisition of Carrizo Oil & Gas, Inc. ("Carrizo"), the Company doubled its core acreage position in the Delaware Basin and entered the Eagle Ford Shale. The Company's primary operations in the Permian Basin reflect a high-return, oil-weighted drilling inventory with multiple prospective horizontal development intervals and are complemented by a well-established and repeatable free cash flow generating business in the Eagle Ford Shale.

Note 2 – Summary of Significant Accounting Policies

Basis of Presentation and Principles of Consolidation

The consolidated financial statements include the accounts of the Company after elimination of intercompany transactions and balances and are presented in accordance with U.S. generally accepted accounting principles ("GAAP"). The Company proportionately consolidates its undivided interests in oil and gas properties as well as investments in unincorporated entities, such as partnerships and limited liability companies where the Company, as a partner or member, has undivided interests in the oil and gas properties. In the opinion of management, the accompanying audited consolidated financial statements reflect all adjustments, including normal recurring adjustments and all intercompany account balance and transaction eliminations, necessary to present fairly the Company's financial position, results of its operations and cash flows for the periods indicated. Certain prior year amounts have been reclassified to conform to current year presentation.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make judgments affecting estimates and assumptions for reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Estimates of proved oil and gas reserves are used in calculating depreciation, depletion and amortization ("DD&A") of proved oil and gas property costs, the present value of estimated future net revenues included in the full cost ceiling test, estimates of future taxable income used in assessing the realizability of deferred tax assets, and the estimated timing of cash outflows underlying asset retirement obligations. There are numerous uncertainties inherent in the estimation of proved oil and gas reserves and in the projection of future rates of production and the timing of development expenditures. Other significant estimates are involved in determining asset retirement obligations, acquisition date fair values of assets acquired and liabilities assumed, impairments of unevaluated leasehold costs, fair values of commodity derivative assets and liabilities, fair values of contingent consideration arrangements, grant date fair value of stock-based awards, and contingency, litigation, and environmental liabilities. Actual results could differ from those estimates.

Cash and Cash Equivalents

The Company considers all highly liquid investments with original maturities of three months or less to be cash equivalents.

Accounts Receivable, Net

Accounts receivable, net consists primarily of receivables from oil, natural gas, and NGL purchasers and joint interest owners in properties the Company operates. The Company generally has the right to withhold future revenue distributions to recover past due receivables from joint interest owners. Generally, the Company's oil, natural gas, and NGL receivables are collected within 30 to 90 days. The Company's allowance for doubtful accounts and bad debt expense was immaterial for all period presented.

Concentration of Credit Risk and Major Customers

The concentration of accounts receivable from entities in the oil and gas industry may impact the Company's overall credit risk such that these entities may be similarly affected by changes in economic and other industry conditions. The Company does not believe the loss of any one of its purchasers would materially affect its ability to sell the oil and gas it produces as other purchasers are available in its primary areas of activity. The Company had the following major customers that represented 10% or more of its total revenues for at least one of the periods presented:

	Years Ended December 31,		
	2019	**2018**	**2017**
Rio Energy International, Inc.	26%	28%	17%
Enterprise Crude Oil, LLC	19%	14%	18%
Plains Marketing, L.P.	15%	21%	29%
Shell Trading Company	10%	*	*

* - Less than 10% for the applicable year.

The Company's counterparties to its commodity derivative instruments include lenders under the Company's credit agreement ("Lender Counterparty") as well as counterparties who are not lenders under the Company's credit agreement ("Non-Lender Counterparty"). As each Lender Counterparty has an investment grade credit rating and the Company has obtained a guaranty from each Non-Lender Counterparty's parent company which has an investment grade credit rating, the Company believes it does not have significant credit risk with its commodity derivative instrument counterparties. Although the Company does not currently anticipate nonperformance from its counterparties, it continually monitors the credit ratings of each Lender Counterparty and each Non-Lender Counterparty's parent company. The Company executes its derivative instruments with multiple counterparties to minimize its credit exposure to any individual counterparty.

Oil and Natural Gas Properties

The Company uses the full cost method of accounting under which all productive and nonproductive costs directly associated with property acquisition, exploration, and development activities are capitalized as oil and gas properties. Internal costs that are directly related to acquisition, exploration, and development activities, including salaries, benefits, and stock-based compensation, are capitalized to either evaluated or unevaluated oil and gas properties based on the type of activity. Internal costs related to production and similar activities are expensed as incurred.

Proceeds from the sale or disposition of evaluated and unevaluated oil and natural gas properties are accounted for as a reduction of evaluated oil and gas property costs unless the sale significantly alters the relationship between capitalized costs and proved reserves, in which case a gain or loss is recognized. For the years ended December 31, 2019, 2018 and 2017, the Company did not have any sales of oil and gas properties that significantly altered such relationship.

Capitalized oil and gas property costs are amortized on an equivalent unit-of-production method, converting natural gas to barrels of oil equivalent at the ratio of six thousand cubic feet of gas to one barrel of oil, which represents their approximate relative energy content. The equivalent unit-of-production depletion rate is computed on a quarterly basis by dividing current quarter production by proved oil and gas reserves at the beginning of the quarter then applying such amortization rate to evaluated oil and gas property costs, which includes estimated asset retirement costs, less accumulated amortization, plus estimated future expenditures to be incurred in developing proved reserves, net of estimated salvage values.

Excluded from this amortization are costs associated with unevaluated leasehold and seismic costs associated with specific unevaluated properties and related capitalized interest. Unevaluated property costs are transferred to evaluated property costs at such time as wells are completed on the properties or the Company determines that these costs have been impaired. The Company assesses properties on an individual basis or as a group and considers the following factors, among others, to determine if these costs have been impaired: exploration program and intent to drill, remaining lease term, and the assignment of proved reserves. Geological and geophysical costs not associated with specific prospects are recorded to evaluated oil and gas property costs as incurred. The amount of interest costs capitalized is determined on a quarterly basis based on the average balance of unproved properties and the weighted average interest rate of outstanding borrowings. Capitalized interest cannot exceed gross interest expense.

Under full cost accounting rules, the Company reviews the net book value of its oil and gas properties each quarter. Under these rules, the net book value of oil and gas properties, less related deferred income taxes, are limited to the "cost center ceiling" equal to (i) the sum of (a) the present value of estimated future net revenues from proved oil and gas reserves, less estimated future expenditures to be incurred in developing and producing the proved reserves computed using a discount factor of 10%, (b) the costs of unevaluated properties not being amortized, and (c) the lower of cost or estimated fair value of unevaluated properties included in the costs being amortized; less (ii) related income tax effects. Any excess of the net book value of oil and gas properties, less related deferred income taxes, over the cost center ceiling is recognized as a write-down of evaluated oil and gas properties. A write-down recognized in one period may not be reversed in a subsequent period even if higher commodity prices in the future result in a cost center ceiling in excess of the net book value of oil and gas properties, less related deferred income taxes.

The estimated future net revenues used in the cost center ceiling are calculated using the average realized prices for sales of oil, NGLs, and natural gas on the first calendar day of each month during the 12-month period prior to the end of the current quarter ("12-Month Average Realized Price"), held flat for the life of the production, except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts. Prices do not include the impact of commodity derivative instruments as the Company elected not to meet the criteria to qualify its commodity derivative instruments for hedge accounting treatment. The Company did not recognize a write-down of evaluated oil and natural gas properties for the years ended December 31, 2019, 2018, and 2017.

Other Property and Equipment

The Company depreciates its other property and equipment using the straight-line method based on estimated useful lives of three to twenty years. Depreciation expense of $0.7 million, $1.1 million and $0.9 million relating to other property and equipment was included in "General and administrative expense" in the consolidated statements of operations for the years ended December 31, 2019, 2018 and 2017, respectively. The Company reviews its other property and equipment for impairment when indicators of impairment exist.

Deferred Financing Costs

Deferred financing costs associated with the Company's senior notes are classified as a reduction of the related senior notes carrying value on the consolidated balance sheets and are amortized to interest expense using the straight-line method over the terms of the related senior notes. Deferred financing costs associated with the revolving credit facility are classified in "Other long-term assets" in the consolidated balance sheets and are amortized to interest expense using the straight-line method over the term of the facility. Amortization of deferred financing costs, net of amortization of premiums, of $2.9 million, $2.5 million and $2.2 million were recorded for the years ended December 31, 2019, 2018 and 2017, respectively.

Asset Retirement Obligations

The Company records an estimate of the fair value of liabilities for obligations associated with plugging and abandoning oil and gas wells, removing production equipment and facilities and restoring the surface of the land in accordance with the terms of oil and gas leases and applicable local, state and federal laws. Estimates involved in determining asset retirement obligations include the future plugging and abandonment costs of wells and related facilities, the ultimate productive life of the properties, a credit-adjusted risk-free discount rate and an inflation factor in order to determine the present value of the asset retirement obligation. The present value of the asset retirement obligations is accreted each period and the increase to the obligation is reported in "Depreciation, depletion and amortization" in the consolidated statements of operations. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation liability, a corresponding adjustment is made to evaluated properties in the consolidated balance sheets. See "Note 14 - Asset Retirement Obligations" for additional information.

Derivative Instruments

The Company uses commodity derivative instruments to mitigate the effects of commodity price volatility for a portion of its forecasted sales of production and achieve a more predictable level of cash flow. All commodity derivative instruments are recorded in the consolidated balance sheets as either an asset or liability measured at fair value. The Company nets its commodity derivative instrument fair value amounts executed with the same counterparty to a single asset or liability pursuant to International Swap Dealers Association Master Agreements ("ISDAs"), which provide for net settlement over the term of the contract and in the event of default or termination of the contract. The Company does not enter into commodity derivative instruments for speculative purposes.

The Company is also party to contingent consideration arrangements that include obligations to pay or rights to receive additional consideration if commodity prices exceed specified thresholds during certain periods in the future. These contingent consideration assets and liabilities are required to be bifurcated and accounted for separately as derivative instruments as they are not considered to be clearly and closely related to the host contract, and recognized at their acquisition or divestiture date fair value in the consolidated balance sheets.

The Company has elected not to meet the criteria to qualify its commodity derivative instruments for hedge accounting treatment. As such, all gains and losses as a result of changes in the fair value of commodity derivative instruments, as well as its contingent consideration arrangements, are recognized as "(Gain) loss on derivative contracts" in the consolidated statements of operations in the period in which the changes occur. See “Note 8 - Derivative Instruments and Hedging Activities” and “Note 9 - Fair Value Measurements” for further discussion.

Revenue Recognition

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. Revenue is recognized at the point in time when control of the product transfers to the customer. Revenue accruals are recorded monthly and are based on estimated production delivered to a purchaser and the expected price to be received. Variances between estimates and the actual amounts received are recorded in the month payment is received. See “Note 3 - Revenue Recognition” for further discussion.

Income Taxes

Income taxes are recognized based on earnings reported for tax return purposes in addition to a provision for deferred income taxes. Deferred income taxes are recognized at the end of each reporting period for the future tax consequences of cumulative temporary differences between the tax basis of assets and liabilities and their reported amounts in the Company’s consolidated financial statements based on existing tax laws and enacted statutory tax rates applicable to the periods in which the temporary differences are expected to affect taxable income. GAAP requires the recognition of a deferred tax asset for net operating loss carryforwards and tax credit carryforwards. The Company assesses the realizability of its deferred tax assets on a quarterly basis by considering all available evidence (both positive and negative) to determine whether it is more likely than not that all or a portion of the deferred tax assets will not be realized and a valuation allowance is required. As of December 31, 2019 and 2018, the Company did not have a valuation allowance against its deferred tax assets. See “Note 12 - Income Taxes” for further discussion.

Share-Based Compensation

The Company grants restricted stock unit awards that may be settled in common stock (“RSU Equity Awards”) or cash (“Cash-Settled RSU Awards”), some of which are subject to achievement of certain performance conditions. In addition, as a result of the Merger, all stock appreciation rights to be settled in cash (“Cash SARs”) previously granted by Carrizo that were outstanding as of closing were canceled and converted into a vested Cash SAR covering shares of the Company’s common stock. Share-based compensation expense is recognized as “General and administrative expense” in the consolidated statements of operations. The Company accounts for forfeitures of equity-based incentive awards as they occur. See “Note 10 - Share-Based Compensation” for further details of the awards discussed below.

RSU Equity Awards and Cash-Settled RSU Awards. Share-based compensation expense for RSU Equity Awards is based on the grant-date fair value and recognized over the vesting period (generally three years for employees and one year for non-employee directors) using the straight-line method. For RSU Equity Awards with vesting terms subject to a performance condition, share-based compensation expense is based on the fair value measured at each reporting period as calculated using a Monte Carlo pricing model with the estimated value recognized over the vesting period (generally three years). Cash-Settled RSU Awards subject to a performance condition that the Company expects or is required to settle in cash, are accounted for as liabilities with share-based compensation expense based on the fair value measured at each reporting period as calculated using a Monte Carlo pricing model, with the estimated fair value recognized over the vesting period (generally three years).

Cash SARs. Cash SARs previously granted by Carrizo that were outstanding at closing of the Merger were canceled and converted into a Cash SAR covering shares of the Company’s common stock, with the conversion calculated as prescribed in the agreement governing the Merger. The Cash SARs were recorded at their acquisition date fair value, which was determined using a Black-Scholes-Merton option pricing model, with the fair value liability subsequently remeasured at the end of each reporting period. The liability for Cash SARs is classified as “Other current liabilities” in the consolidated balance sheets as all outstanding awards are vested. The Cash SARs will expire between one and seven years, depending on the date of grant.

Supplemental Cash Flow Information

The following table sets forth supplemental cash flow information for the periods indicated:

	Years Ended December 31,		
	2019	2018	2017
		(In thousands)	
Interest paid, net of capitalized amounts	$—	$—	$—
Income taxes paid (1)	—	—	—
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows from operating leases	$3,414	$—	$—
Investing cash flows from operating leases	32,529	—	—
Non-cash investing and financing activities:			
Change in accrued capital expenditures	($31,475)	($52,757)	($39,532)
Change in asset retirement costs	13,559	8,730	(607)
Contingent consideration arrangement	8,512	—	—
ROU assets obtained in exchange for lease liabilities:			
Operating leases	$66,914	$—	$—
Financing leases	2,197	—	—

(1) The Company did not pay any federal income tax for any of the years in the three year period ending December 31, 2019.

Earnings per Share

The Company's basic net income attributable to common shareholders per common share is based on the weighted average number of shares of common stock outstanding for the period. Diluted net income attributable to common shareholders per common share is calculated using the treasury stock method and is based on the weighted average number of common shares and all potentially dilutive common shares outstanding during the year which include RSU Equity Awards and common stock warrants. See "Note 6 - Earnings Per Share" for further discussion.

Industry Segment and Geographic Information

The Company operates in one industry segment, which is the exploration, development, and production of crude oil, NGLs, and natural gas. All of the Company's operations are located in the United States and currently all revenues are attributable to customers located in the United States.

Recently Adopted Accounting Standards

Leases. In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842): Amendments to the FASB Accounting Standards Codification. In January 2018, the FASB issued ASU No. 2018-01, Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842. In July 2018, the FASB issued ASU No. 2018-11, Leases (Topic 842): Targeted Improvements. In March 2019, the FASB issued ASU No. 2019-01, Leases (Topic 842): Codification Improvements. Together these related amendments to GAAP represent ASC Topic 842, Leases ("ASC 842").

Effective January 1, 2019, the Company adopted ASU 842, using the modified retrospective approach and did not have a cumulative-effect adjustment in retained earnings as a result of the adoption. ASC 842 requires lessees to recognize a liability representing the obligation to make lease payments and a related right-of-use ("ROU") asset for virtually all lease transactions and disclose key quantitative and qualitative information about leasing arrangements. However, ASC 842 does not apply to leases to explore for or use minerals, oil or natural gas resources, including the right to explore for those natural resources and rights to use the land in which those natural resources are contained. The Company engaged a third-party consultant to assist with assessing its existing contracts, as well as future potential contracts, and to determine the impact of its application on its consolidated financial statements and related disclosures. The contract evaluation process included review of drilling rig contracts, office facility leases, compressors, field vehicles and equipment, general corporate leased equipment, and other existing arrangements to support its operations that may contain a lease component.

Upon adoption, the Company implemented policy elections and practical expedients which include the following:

- package of practical expedients which allows the Company to forego reassessing contracts that commenced prior to adoption that were properly evaluated under legacy lease accounting guidance
- excluding ROU assets and lease liabilities for leases with terms that are less than one year;
- combining lease and non-lease components and accounting for them as a single lease (elected by asset class);
- excluding land easements that existed or expired prior to adoption; and

- policy election that eliminates the need for adjusting prior period comparable financial statements prepared under legacy lease accounting guidance.

Through the implementation process, the Company evaluated each of its lease arrangements and enhanced its systems to track and calculate additional information required upon adoption of this standard. Adoption of ASC 842 did not materially change the Company's consolidated statements of operations or consolidated statements of cash flows. See "Note 13 - Leases" for further discussion.

Recently Issued ASUs

None that are expected to have a material impact on our financial statements.

Note 3 – Revenue Recognition

Revenue from contracts with customers

Oil sales

Under the Company's oil sales contracts it sells oil production at the point of delivery and collects an agreed upon index price, net of pricing differentials. The Company recognizes revenue when control transfers to the purchaser at the point of delivery at the net price received.

Natural gas sales

Under the Company's natural gas sales processing contracts, it delivers natural gas to a midstream processing entity. The midstream processing entity gathers and processes the natural gas and remits proceeds to the Company for the resulting sale of natural gas. The revenue received from the sale of NGLs associated with certain contracts is included in natural gas sales. Under these processing agreements, when control of the natural gas changes at the point of delivery, the treatment of gathering and treating fees are recorded net of revenues. For other contracts that were assumed in the Carrizo Acquisition, defined below, where the Company maintains control throughout processing, the Company records NGL revenue separately on its consolidated statement of operations and presents the gathering a treating fees as an expense recorded in lease operating expense.

For the majority of the Company's natural gas sales processing contracts, gathering and treating fees have historically been recorded as an expense in lease operating expense in the statement of operations. The Company modified the presentation of revenues and expenses to include these fees net of revenues effective January 1, 2018 upon adopting ASC 606 - Revenue from Contracts with Customers. For the years ended December 31, 2019 and 2018, $10.5 million and $7.6 million of gathering and treating fees were recognized and recorded as a reduction to natural gas revenues in the consolidated statement of operations, respectively. For the year ended December 31, 2017, $3.4 million of gathering and treating fees were recognized and recorded as part of lease operating expense in the consolidated statement of operations.

Accounts receivable from revenues from contracts with customers

Net accounts receivable include amounts billed and currently due from revenues from contracts with customers of our oil and natural gas production, which had a balance at December 31, 2019 and 2018 of $165.3 million and $87.1 million, respectively, and are presented in "Accounts receivable, net" in the consolidated balance sheets. The increase from December 31, 2018 is primarily due to the Carrizo Acquisition.

Transaction price allocated to remaining performance obligations

For the Company's product sales that have a contract term greater than one year, it has utilized the practical expedient in Accounting Standards Codification 606-10-50-14, which states the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, each unit of product generally represents a separate performance obligation; therefore future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

Prior period performance obligations

The Company records revenue in the month production is delivered to the purchaser. However, settlement statements for sales may not be received for 30 to 90 days after the date production is delivered, and as a result, the Company is required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. The Company records the differences between estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. The Company has existing internal controls for its revenue estimation process and related accruals, and any identified differences between its revenue estimates and actual revenue received historically have not been significant.

Note 4 – Acquisitions and Divestitures

2019 Acquisitions and Divestitures

Carrizo Oil & Gas, Inc. Merger. On December 20, 2019, the Company completed its acquisition of Carrizo in an all-stock transaction (the "Merger" or the "Carrizo Acquisition"). Under the terms of the Merger, each outstanding share of Carrizo common stock was converted into 1.75 shares of the Company's common stock. The Company issued approximately 168.2 million shares of common stock at a price of $4.55 per share, resulting in total consideration paid by the Company to the former Carrizo shareholders of approximately $765.4 million. In connection with the closing of the Merger, the Company funded the redemption of Carrizo's 8.875% Preferred Stock, repaid the outstanding principal under Carrizo's revolving credit facility and assumed all of Carrizo's senior notes. See "Note 7 - Borrowings" for further details.

The Merger was accounted for as a business combination, therefore, the purchase price was allocated to the assets acquired and the liabilities assumed based on their estimated acquisition date fair values based on then currently available information. A combination of a discounted cash flow model and market data was used by a third-party specialist in determining the fair value of the oil and gas properties. Significant inputs into the calculation included future commodity prices, estimated volumes of oil and gas reserves, expectations for timing and amount of future development and operating costs, future plugging and abandonment costs and a risk adjusted discount rate. Certain data necessary to complete the purchase price allocation is not yet available, including final tax returns that provide the underlying tax basis of Carrizo's assets and liabilities. The company expects to complete the purchase price allocation during the 12-month period following the acquisition date.

The following table sets forth the Company's preliminary allocation of the purchase price to the assets acquired and liabilities assumed as of the acquisition date.

	Preliminary Purchase Price Allocation
	(In thousands)
Consideration:	
Fair value of the Company's common stock issued	$765,373
Total consideration	$765,373
Liabilities:	
Accounts payable	$37,657
Revenues and royalties payable	52,449
Operating lease liabilities - current	29,924
Fair value of derivatives - current	61,015
Other current liabilities	82,084
Long-term debt	1,984,135
Operating lease liabilities - non-current	30,070
Asset retirement obligation	26,151
Fair value of derivatives - non-current	26,960
Other long-term liabilities	17,260
Common stock warrants	10,029
Total liabilities assumed	$2,357,734
Assets:	
Accounts receivable, net	$48,479
Fair value of derivatives - current	17,451
Other current assets	4,945
Evaluated oil and natural gas properties	2,133,280
Unevaluated properties	682,928
Other property and equipment	9,614
Fair value of derivatives - non-current	4,518
Deferred tax asset	159,320
Operating lease right-of-use-assets	59,994
Other long term assets	2,578
Total assets acquired	$3,123,107

Approximately $28.6 million of revenues and $7.0 million of direct operating expenses attributed to the Carrizo Acquisition are included in the Company's consolidated statements of operations for the period from the closing date on December 20, 2019 through December 31, 2019.

Pro Forma Operating Results (Unaudited). The following unaudited pro forma combined condensed financial data for the years ended December 31, 2019 and 2018 was derived from the historical financial statements of the Company giving effect to the Merger, as if it had occurred on January 1, 2018. The below information reflects pro forma adjustments for the issuance of the Company's common stock in exchange for Carrizo'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 Carrizo's outstanding shares of common stock and equity awards as of the closing date of the Merger, (ii) the depletion of Carrizo's fair-valued proved oil and natural 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 $58.8 million for the year ended December 31, 2019 and acquisition-related costs incurred by Carrizo that totaled approximately $15.6 million for the year ended December 31, 2019. The pro forma results of operations do not include any cost savings or other synergies that may result from the Merger or any estimated costs that have been or will be incurred by the Company to integrate the Carrizo assets. The pro forma financial data does not include the pro forma results of operations for any other acquisitions made during the periods presented, as they were primarily acreage acquisitions and their results were not deemed material.

The pro forma consolidated statements of operations data has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the Merger taken place on January 1, 2018 and is not intended to be a projection of future results.

	Years Ended December 31,	
	2019	2018
	(In thousands)	
Revenues	$1,620,357	$1,661,171
Income from operations	614,668	767,628
Net income	369,777	734,527
Basic earnings per common share	0.89	$1.87
Diluted earnings per common share	0.89	$1.87

During 2019, in conjunction with the Carrizo Acquisition, the Company incurred costs totaling $74.4 million comprised of severance costs of $28.8 million and other merger and integration expenses of $45.6 million. As of December 31, 2019, $52.4 million remained accrued and is included as a component of "Accounts payable and accrued liabilities" in the consolidated balance sheets.

Ranger Divestiture. In the second quarter of 2019, the Company completed its divestiture of certain non-core assets in the southern Midland Basin (the "Ranger Divestiture") for net cash proceeds of $244.9 million. The transaction also provided for potential additional contingent consideration of up to $60.0 million based on West Texas Intermediate average annual pricing over a three-year period. See "Note 8 - Derivative Instruments and Hedging Activities" and "Note 9 - Fair Value Measurements" for further discussion of this contingent consideration arrangement. The divestiture encompasses the Ranger operating area in the southern Midland Basin which includes approximately 9,850 net Wolfcamp acres with an average 66% working interest. The net cash proceeds were recognized as a reduction of evaluated oil and gas properties with no gain or loss recognized.

2018 Acquisitions and Divestitures

On August 31, 2018, the Company completed the acquisition of approximately 28,000 net surface acres in the Spur operating area, located in the Delaware Basin, from Cimarex Energy Company, for a net cash consideration of approximately $539.5 million (the "Delaware Asset Acquisition"). The Company funded the Delaware Asset Acquisition with net proceeds from both the common stock offering completed on May 30, 2018 and the issuance of the 6.375% Senior Notes. See "Note 7 - Borrowings" and "Note 11 - Stockholders' Equity" for further details of these offerings.

The Delaware Asset Acquisition was accounted for as a business combination, therefore, the purchase price was allocated to the assets acquired and the liabilities assumed based on their estimated acquisition date fair values based on then currently available information. A combination of a discounted cash flow model and market data was used by a third-party specialist in determining the fair value of the oil and gas properties. Significant inputs into the calculation included future commodity prices, estimated volumes of oil and gas reserves, expectations for timing and amount of future development and operating costs, future plugging and abandonment costs and a risk adjusted discount rate. The following table sets forth the Company's allocation of the purchase price to the assets acquired and liabilities assumed as of the acquisition date.

	Purchase Price Allocation
	(In thousands)
Assets	
Oil and natural gas properties	
Evaluated properties	$253,089
Unevaluated properties	287,000
Total oil and natural gas properties	$540,089
Total assets acquired	$540,089
Liabilities	
Asset retirement obligations	($570)
Total liabilities assumed	($570)
Net Assets Acquired	$539,519

Approximately $27.3 million of revenues and $9.9 million of direct operating expenses attributed to the Delaware Asset Acquisition are included in the Company's consolidated statements of operations for the period from the closing date on August 31, 2018 through December 31, 2018.

Pro Forma Operating Results (Unaudited). The following unaudited pro forma financial information presents a summary of the Company's consolidated results of operations for the years ended December 31, 2018 and 2017, assuming the Delaware Asset Acquisition had been completed as of January 1, 2017, including adjustments to reflect the acquisition date fair values assigned to the assets acquired and liabilities assumed. The pro forma financial information does not purport to represent what the actual results of operations would have been had the transactions been completed as of the date assumed, nor is this information necessarily indicative of future consolidated results of operations. The Company believes the assumptions used provide a reasonable basis for reflecting the significant pro forma effects directly attributable to the Delaware Asset Acquisition.

	Years Ended December 31,	
	2018	2017
	(In thousands)	
Revenues	$669,236	$469,896
Income from operations	299,090	209,723
Net income	324,318	181,406
Basic earnings per common share	$1.49	$0.90
Diluted earnings per common share	$1.49	$0.90

Other. In addition, the Company completed various acquisitions of additional working interests and mineral rights, and associated production volumes, in the Company's existing core operating areas within the Permian Basin. In the first quarter of 2018, the Company completed acquisitions within Monarch and WildHorse operating areas for aggregate net cash consideration of approximately $37.8 million. In the fourth quarter of 2018, the Company completed acquisitions of leasehold interests and mineral rights within its WildHorse and Spur operating areas for net cash consideration of approximately $87.9 million.

The Company did not have any material divestitures for the year ended December 31, 2018.

2017 Acquisitions and Divestitures

Ameredev Acquisition. On February 13, 2017, the Company completed the acquisition of 29,175 gross (16,688 net) acres in the Delaware Basin, primarily located in Ward and Pecos Counties, Texas from American Resource Development, LLC, for total cash consideration of $646.6 million, excluding customary purchase price adjustments (the "Ameredev Acquisition"). The Company partially funded the Ameredev Acquisition with net proceeds from the common stock offering completed on December 19, 2016. The Company obtained an 82% average working interest (75% average net revenue interest) in the properties acquired in the Ameredev Acquisition.

The Ameredev Acquisition was accounted for as a business combination, therefore, the purchase price was allocated to the assets acquired and the liabilities assumed based on their estimated acquisition date fair values based on then currently available information. A combination of a discounted cash flow model and market data was used by a third-party specialist in determining the fair value of the oil and gas properties. Significant inputs into the calculation included future commodity prices, estimated volumes of oil and gas reserves, expectations for timing and amount of future development and operating costs, future plugging and abandonment costs and a risk adjusted discount rate. The following table sets forth the Company's allocation of the purchase price to the assets acquired and liabilities assumed as of the acquisition date.

	Purchase Price Allocation
	(In thousands)
Assets	
Oil and natural gas properties	
Evaluated properties	$137,368
Unevaluated properties	509,359
Total oil and natural gas properties	$646,727
Total assets acquired	$646,727
Liabilities	
Asset retirement obligations	($168)
Total liabilities assumed	($168)
Net Assets Acquired	$646,559

Approximately $36.1 million of revenues and $8.5 million of direct operating expenses attributed to the Ameredev Acquisition are included in the Company's consolidated statements of operations for the period from the closing date on February 13, 2017 through December 31, 2017.

Pro Forma Operating Results (Unaudited). The following unaudited pro forma financial information presents a summary of the Company's consolidated results of operations for the year ended December 31, 2017, assuming the Ameredev Acquisition had been completed as of January 1, 2016, including adjustments to reflect the acquisition date fair values assigned to the assets acquired and liabilities assumed. The pro forma financial information does not purport to represent what the actual results of operations would have been had the transactions been completed as of the date assumed, nor is this information necessarily indicative of future consolidated results of operations. The Company believes the assumptions used provide a reasonable basis for reflecting the significant pro forma effects directly attributable to the Ameredev Acquisition.

	Year Ended December 31, 2017
	(In thousands)
Revenues	$369,527
Income from operations	144,104
Net income	115,787
Basic earnings per common share	$0.57
Diluted earnings per common share	$0.57

Other. On June 5, 2017, the Company completed the acquisition of 7,031 gross (2,488 net) acres in the Delaware Basin, located near the acreage acquired in the Ameredev Acquisition discussed above, for aggregate net cash consideration of approximately $52.0 million. The Company funded the cash purchase price with available cash and proceeds from the issuance of an additional $200.0 million of its 6.125% Senior Notes. See "Note 7 - Borrowings" for further details of this offering.

The Company did not have any material divestitures for the year ended December 31, 2017.

Note 5 – Property and Equipment, Net

As of December 31, 2019 and 2018, total property and equipment, net consisted of the following:

	As of December 31,	
	2019	2018
Oil and natural gas properties, full cost accounting method	(In thousands)	
Evaluated properties	$7,203,482	$4,585,020
Accumulated depreciation, depletion, amortization and impairments	(2,520,488)	(2,270,675)
Net evaluated oil and natural gas properties	4,682,994	2,314,345
Unevaluated properties		
Unevaluated leasehold and seismic costs	1,843,725	1,316,190
Capitalized interest	142,399	88,323
Total unevaluated properties	1,986,124	1,404,513
Total oil and natural gas properties, net	$6,669,118	$3,718,858
Other property and equipment	$67,202	$38,463
Accumulated depreciation	(31,949)	(16,562)
Other property and equipment, net	$35,253	$21,901

The Company capitalized internal costs of employee compensation and benefits, including stock-based compensation, directly associated with acquisition, exploration and development activities totaling $36.2 million, $28.0 million and $20.3 million for the years ended December 31, 2019, 2018 and 2017, respectively. The Company capitalized interest costs to unproved properties totaling $78.5 million, $56.2 million and $33.8 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Unevaluated property costs not subject to amortization as of December 31, 2019 consisted of the following:

	2019	2018	2017	2016	Total
			(In thousands)		
Acquisition costs	$682,413	$383,238	$577,959	$115,833	$1,759,443
Exploration costs	43,174	22,384	18,724	—	84,282
Capitalized interest	78,492	56,151	7,756	—	142,399
Total unevaluated properties	$804,079	$461,773	$604,439	$115,833	$1,986,124

Note 6 – Earnings Per Share

Basic earnings (loss) per share is computed by dividing income available to common stockholders by the weighted average number of shares outstanding for the periods presented. The calculation of diluted earnings per share includes the potential dilutive impact of non-vested restricted shares outstanding during the periods presented, as calculated using the treasury stock method, unless their effect is anti-dilutive. The following table sets forth the computation of basic and diluted earnings per share:

	Years Ended December 31,		
	2019	2018	2017
	(In thousands, except per share amounts)		
Net income	$67,928	$300,360	$120,424
Preferred stock dividends	(3,997)	(7,295)	(7,295)
Loss on redemption of preferred stock	(8,304)	—	—
Income available to common stockholders	$55,627	$293,065	$113,129
Basic weighted average common shares outstanding	233,140	216,941	201,526
Dilutive impact of restricted stock	410	655	576
Diluted weighted average common shares outstanding	233,550	217,596	202,102
Income Available to Common Stockholders Per Common Share			
Basic	$0.24	$1.35	$0.56
Diluted	$0.24	$1.35	$0.56
Restricted stock [(1)]	998	89	16

(1) Shares excluded from the diluted earnings per share calculation because their effect would be anti-dilutive.

Note 7 – Borrowings

The Company's borrowings consisted of the following:

	As of December 31,	
	2019	2018
	(In thousands)	
Senior Secured Revolving Credit Facility due 2024	$1,285,000	$200,000
6.25% Senior Notes due 2023 [(1)]	650,000	—
6.125% Senior Notes due 2024	600,000	600,000
8.25% Senior Notes due 2025 [(1)]	250,000	—
6.375% Senior Notes due 2026	400,000	400,000
Total principal outstanding	3,185,000	1,200,000
Unamortized premium for 6.125% Senior Notes	5,344	6,469
Unamortized premium for 6.25% Senior Notes	4,838	—
Unamortized premium for 8.25% Senior Notes	5,286	—
Unamortized deferred financing costs for Senior Notes	(14,359)	(16,996)
Total carrying value of borrowings [(2)]	$3,186,109	$1,189,473

(1) As a result of the Merger, the Company became successor-in-interest to the indenture governing the 6.25% Senior Notes and 8.25% Senior Notes.
(2) Excludes unamortized deferred financing costs related to the Company's senior secured revolving credit facility of $22.2 million and $6.1 million as of December 31, 2019 and 2018, respectively.

Senior Secured Revolving Credit Facility

On May 25, 2017, the Company entered into the Sixth Amended and Restated Credit Agreement to the Credit Facility (the "Prior Credit Facility") with a syndicate of lenders. The Prior Credit Facility provided for interest-only payments until May 25, 2023, when the Prior Credit Facility would mature and any outstanding borrowings would become due. The maximum credit amount under the Prior Credit Facility was $2.0 billion.

Effective May 1, 2019, the Company entered into the third amendment to the Prior Credit Facility to, among other things: (i) reaffirm the borrowing base at $1.1 billion, excluding the Ranger assets sold; and (ii) amend various covenants and terms to reflect current market trends.

As a result of entering into the Credit Facility, as defined below, the Company terminated the Prior Credit Facility. As a result of terminating the Prior Credit Facility, the Company recorded a loss on extinguishment of debt of $4.9 million, which was comprised solely of the write-off of unamortized deferred financing costs associated with the Prior Credit Facility.

On December 20, 2019, upon consummation of the Merger, the Company entered into the credit agreement with a syndicate of lenders (the "Credit Facility"). The Credit Facility provides for interest-only payments until December 20, 2024 (subject to springing maturity dates of (i) January 14, 2023 if the 6.25% Senior Notes are outstanding at such time and (ii) July 2, 2024 if the 6.125% Senior Notes are outstanding at such time), when the Credit Facility matures and any outstanding borrowings are due. The maximum credit amount under the Credit Facility is $5.0 billion. The borrowing base under the Credit Facility is subject to regular redeterminations in the spring and fall of each year, as well as special redeterminations described in the credit agreement, which in each case may reduce the amount of the borrowing base. The Credit Facility is secured by first preferred mortgages covering the Company's major producing properties. The capitalized terms which are not defined in this description of the revolving credit facility shall have the meaning given to such terms in the credit agreement.

As of December 31, 2019, the borrowing base under the Credit Facility was $2.5 billion, with an elected commitment amount of $2.0 billion, and borrowings outstanding of $1.3 billion at a weighted average interest rate of 3.56%. The Company also had $17.7 million in letters of credit outstanding under the Credit Facility.

Borrowings outstanding under the credit agreement bear interest at the Company's option at either (i) a base rate for a base rate loan plus a margin between 0.25% to 1.25%, where the base rate is defined as the greatest of the prime rate, the federal funds rate plus 0.50% and the adjusted LIBO rate plus 1.00%, or (ii) an adjusted LIBO rate for a Eurodollar loan plus a margin between 1.25% to 2.25%. At any time the Leverage Ratio, as defined in the credit agreement, is greater than 3.00 to 1.00, the base rate and Eurodollar loans are increased 0.25%. The Company also incurs commitment fees at rates ranging between 0.375% to 0.500% as set forth in the table below on the unused portion of lender commitments, which are included in "Interest expense, net" in the consolidated statements of operations.

6.375% Senior Notes

On June 7, 2018, the Company issued $400.0 million aggregate principal amount of 6.375% Senior Notes due 2026 (the "6.375% Senior Notes"), which mature on July 1, 2026 and have interest payable semi-annually each January 1 and July 1. The Company used the net proceeds from the offering of approximately $394.0 million, after deducting initial purchasers' discounts and estimated offering expenses, to fund a portion of the Delaware Asset Acquisition described above. The 6.375% Senior Notes are guaranteed on a senior unsecured basis by the Company's wholly-owned subsidiary, Callon Petroleum Operating Company, and may be guaranteed by certain future subsidiaries. The subsidiary guarantor is 100% owned, all of the guarantees are full and unconditional and joint and several, the parent company has no independent assets or operations and any subsidiaries of the parent company other than the subsidiary guarantor are minor.

The Company may redeem the 6.375% Senior Notes in accordance with the following terms: (1) prior to July 1, 2021, a redemption of up to 35% of the principal in an amount not greater than the net proceeds from certain equity offerings, and within 180 days of the closing date of such equity offerings, at a redemption price of 106.375% of principal, plus accrued and unpaid interest, if any, to the date of the redemption, if at least 65% of the principal will remain outstanding after such redemption; (2) prior to July 1, 2021, a redemption of all or part of the principal at a price of 100% of principal of the amount redeemed, plus an applicable make-whole premium and accrued and unpaid interest, if any, to the date of the redemption; and (3) a redemption, in whole or in part, at a redemption price, plus accrued and unpaid interest, if any, to the date of the redemption, (i) of 103.188% of principal if the redemption occurs on or after July 1, 2021, but before July 1, 2022, and (ii) of 102.125% of principal if the redemption occurs on or after July 1, 2022, but before July 1, 2023, and (iii) of 101.063% of principal if the redemption occurs on or after July 1, 2023, but before July 1, 2024, and (iv) of 100% of principal if the redemption occurs on or after July 1, 2024.

Following a change of control, each holder of the 6.375% Senior Notes may require the Company to repurchase all or a portion of the 6.375% Senior Notes at a price of 101% of principal of the amount repurchased, plus accrued and unpaid interest, if any, to the date of repurchase.

6.125% Senior Notes

On October 3, 2016, the Company issued $400.0 million aggregate principal amount of 6.125% Senior Notes due 2024 (the "6.125% Senior Notes), which mature on October 1, 2024 and have interest payable semi-annually each April 1 and October 1. The 6.125% Senior Notes are guaranteed on a senior unsecured basis by the Company's wholly-owned subsidiary, Callon Petroleum Operating Company, and may be guaranteed by certain future subsidiaries. The subsidiary guarantor is 100% owned, all of the guarantees are full and unconditional and joint and several, the parent company has no independent assets or operations and any subsidiaries of the parent company other than the subsidiary guarantor are minor.

On May 19, 2017, the Company issued an additional $200.0 million aggregate principal amount of its 6.125% Senior Notes which with the existing $400.0 million aggregate principal amount of 6.125% Senior Notes are treated as a single class of notes under the indenture. The Company used a portion of the net proceeds from the offering of approximately $206.1 million, including a premium issue price of 104.125% and after deducting initial purchasers' discounts and estimated offering expenses, to fund the acquisition completed on June 5, 2017 with the remainder for general corporate purposes.

The Company may redeem all or a portion of the 6.125% Senior Notes at redemption prices decreasing from 104.594% to 100% of the principal amount on October 1, 2022, plus accrued and unpaid interest.

Following a change of control, each holder of the 6.125% Senior Notes may require the Company to repurchase all or a portion of the 6.125% Senior Notes at a price of 101% of principal of the amount repurchased, plus accrued and unpaid interest, if any, to the date of repurchase.

Senior Notes Assumed in Merger

On December 20, 2019, upon consummation of the Merger, the Company became successor-in-interest to the indenture governing the 8.25% Senior Notes due 2025 (the "8.25% Senior Notes") and the 6.25% Senior Notes due 2023 (the "6.25% Senior Notes"). Both the 8.25% Senior Notes and the 6.25% Senior Notes are guaranteed on a senior unsecured basis by the Company's wholly-owned subsidiary, Callon Petroleum Operating Company, and may be guaranteed by certain future subsidiaries.

8.25% Senior Notes. The 8.25% Senior Notes mature on July 15, 2025 and have interest payable semi-annually each January 15 and July 15. Before July 15, 2020, the Company may, at its option, redeem all or a portion of the 8.25% Senior Notes at 100% of the principal amount plus accrued and unpaid interest and a make-whole premium. Thereafter, the Company may redeem all or a portion of the 8.25% Senior Notes at redemption prices decreasing annually from 106.188% to 100% of the principal amount redeemed plus accrued and unpaid interest.

6.25% Senior Notes. The 6.25% Senior Notes mature on April 15, 2023 and have interest payable semi-annually each April 15 and October 15. The Company may redeem all or a portion of the 6.25% Senior Notes at redemption prices decreasing from 103.125% to 100% of the principal amount on April 15, 2021, plus accrued and unpaid interest.

If a Change of Control (as defined in the indenture governing the 8.25% Senior Notes and the 6.25% Senior Notes) occurs, the Company may be required by holders to repurchase the 8.25% Senior Notes and the 6.25% Senior Notes for cash at a price equal to 101% of the principal amount purchased, plus any accrued and unpaid interest. The indenture governing the 8.25% Senior Notes and the 6.25% Senior Notes contains covenants that, among other things, limit the Company's ability and the ability of its restricted subsidiaries to: pay distributions on, purchase or redeem the Company's capital stock or redeem the Company's subordinated debt; make investments; incur or guarantee additional indebtedness or issue certain types of equity securities; create certain liens; sell assets; consolidate, merge or transfer all or substantially all of the Company's assets; enter into agreements that restrict distributions or other payments from the Company's restricted subsidiaries to the Company; engage in transactions with affiliates; and create unrestricted subsidiaries. The indenture governing the 8.25% Senior Notes and the 6.25% Senior Notes also contains customary events of default, including those related to failure to comply with the terms of the 8.25% Senior Notes and the 6.25% Senior Notes, certain cross defaults of other indebtedness and mortgages, and certain failures to pay final judgments.

Restrictive covenants

The Company's credit facility and the indentures governing its senior notes contain various covenants including restrictions on additional indebtedness, payment of cash dividends and maintenance of certain financial ratios. The Company was in compliance with these covenants at December 31, 2019.

Note 8 – Derivative Instruments and Hedging Activities

Objectives and strategies for using derivative instruments

The Company is exposed to fluctuations in oil and natural gas prices received for its production. Consequently, the Company believes it is prudent to manage the variability in cash flows on a portion of its oil and natural gas production. The Company utilizes a mix of collars, swaps, and put and call options to manage fluctuations in cash flows resulting from changes in commodity prices. The Company does not use these instruments for speculative or trading purposes.

Counterparty risk and offsetting

The use of derivative instruments exposes the Company to the risk that a counterparty will be unable to meet its commitments. While the Company monitors counterparty creditworthiness on an ongoing basis, it cannot predict sudden changes in counterparties' creditworthiness. In addition, even if such changes are not sudden, the Company may be limited in its ability to mitigate an increase in counterparty credit risk. Should one of these counterparties not perform, the Company may not realize the benefit of some of its derivative instruments under lower commodity prices while continuing to be obligated under higher commodity price contracts subject to any right of offset under the agreements. Counterparty credit risk is considered when determining the fair value of a derivative instrument. "See Note 9 - Fair Value Measurements" for further discussion.

The Company executes commodity derivative contracts under master agreements with netting provisions that provide for offsetting assets against liabilities. In general, if a party to a derivative transaction incurs an event of default, as defined in the applicable agreement, the other party will have the right to demand the posting of collateral, demand a cash payment transfer, or terminate the arrangement.

Financial statement presentation and settlements

Settlements of the Company's commodity derivative instruments are based on the difference between the contract price or prices specified in the derivative instrument and a benchmark price, such as the NYMEX price. To determine the fair value of the Company's derivative instruments, the Company utilizes present value methods that include assumptions about commodity prices based on those observed in underlying markets. See "Note 9 - Fair Value Measurements" for additional information regarding fair value.

Contingent consideration arrangements

Ranger Divestiture. The Company's Ranger Divestiture provides for potential contingent consideration to be received by the Company if commodity prices exceed specified thresholds in each of the next several years. See "Note 4 - Acquisitions and Divestitures" and "Note 9 - Fair Value Measurements" for further discussion. This contingent consideration arrangement is summarized in the table below (in thousands except for per Bbl amounts):

	Year	Threshold (1)	Contingent Receipt - Annual	Threshold (1)	Contingent Receipt - Annual	Period Cash Flow Occurs	Statement of Cash Flows Presentation	Remaining Contingent Receipt - Aggregate Limit (3)	Divestiture Date Fair Value
									$8,512
Pending Settlement	2019	Greater than $60/Bbl, less than $65/Bbl	$—	Equal to or greater than $65/Bbl	$—	1Q20	N/A		
Remaining Potential Settlements	2020-2021	Greater than $60/Bbl, less than $65/Bbl	$9,000	Equal to or greater than $65/Bbl	$20,833	(2)	(2)	$60,000	

(1) The price used to determine whether the specified thresholds have been met is the average of the final monthly settlements for each month during each annual period end for NYMEX Light Sweet Crude Oil Futures, as reported by the CME Group Inc.
(2) Cash received for settlements of contingent consideration arrangements are classified as cash flows from financing activities up to the divestiture date fair value with any excess classified as cash flows from operating activities. Therefore, if the commodity price threshold is reached, $8.5 million of the next contingent receipt will be presented in cash flows from financing activities with the remainder, as well as all subsequent contingent receipts, presented in cash flows from operating activities.
(3) The specified pricing threshold for 2019 was not met. As such, approximately $41.5 million remains for potential settlements in future years.

As a result of the Carrizo Acquisition, the Company assumed all contingent consideration arrangements previously entered into by Carrizo. These contingent consideration arrangements are summarized below:

Contingent ExL Consideration

	Year	Threshold (1)	Period Cash Flow Occurs	Statement of Cash Flows Presentation	Contingent Payment - Annual	Remaining Contingent Payments - Aggregate Limit	Acquisition Date Fair Value
					(In thousands)		
							($69,171)
Pending Settlement	2019	$50.00	1Q20	Investing	($50,000)		
Remaining Potential Settlements	2020-2021	$50.00	(2)	(2)	($50,000)	($75,000) (3)	

(1) The price used to determine whether the specified threshold for each year has been met is the average daily closing spot price per barrel of WTI crude oil as measured by the U.S. Energy Information Administration ("U.S. EIA").
(2) Cash paid for settlements of contingent consideration arrangements are classified as cash flows from financing activities up to the acquisition date fair value with any excess classified as cash flows from operating activities. Therefore, if the commodity price threshold is reached, all of the next contingent payment will be presented in cash flows from financing activities.

(3) In January 2020, the Company paid $50.0 million as the specified pricing threshold was met. Only $25.0 million remains for potential settlements in future years.

Additionally, as part of the Carrizo Acquisition, the Company acquired contingent consideration arrangements where the Company could receive payments if certain pricing thresholds are met, which range between $53.00 - $60.00 per barrel of oil or $3.18 - $3.30 per MMBtu of natural gas. In January 2020, the Company received $10.0 million as the specified pricing thresholds were met for certain of the contingent consideration arrangements. As such, the aggregate limit of the remaining contingent receipts is $13.0 million and would be settled in January 2021 based on the specified pricing thresholds for 2020.

See "Note 18 - Subsequent Events" for further discussion of the Company's actual settlements of its contingent consideration arrangements subsequent to December 31, 2019.

Derivatives not designated as hedging instruments

The Company records its derivative instruments at fair value in the consolidated balance sheets and records changes in fair value as "(Gain) loss on derivative contracts" in the consolidated statements of operations. Settlements are also recorded as a gain or loss on derivative contracts in the consolidated statements of operations.

As previously discussed, the Company's commodity derivative contracts are subject to master netting arrangements. The Company's policy is to present the fair value of derivative contracts on a net basis in the consolidated balance sheet. The following presents the impact of this presentation to the Company's recognized assets and liabilities for the periods indicated:

	As of December 31, 2019		
	Presented without Effects of Netting	**Effects of Netting**	**As Presented with Effects of Netting**
		(In thousands)	
Commodity derivative instruments	$26,849	($17,511)	$9,338
Contingent consideration arrangements	16,718	—	16,718
Fair value of derivatives - current	$43,567	($17,511)	$26,056
Commodity derivative instruments	—	—	—
Contingent consideration arrangements	9,216	—	9,216
Fair value of derivatives - non current	$9,216	$—	$9,216
Commodity derivative instruments	($38,708)	$17,511	($21,197)
Contingent consideration arrangements	(50,000)	—	(50,000)
Fair value of derivatives - current	($88,708)	$17,511	($71,197)
Commodity derivative instruments	(12,935)	—	(12,935)
Contingent consideration arrangements	(19,760)	—	(19,760)
Fair value of derivatives - non current	($32,695)	$—	($32,695)

	As of December 31, 2018		
	Presented without Effects of Netting	**Effects of Netting**	**As Presented with Effects of Netting**
		(In thousands)	
Fair value of derivatives - current	$78,091	($12,977)	$65,114
Fair value of derivatives - current	($23,457)	$12,977	($10,480)
Fair value of derivatives - non current	(7,440)	—	(7,440)

The components of “(Gain) loss on derivative contracts” are as follows for the respective periods:

	Years Ended December 31,		
	2019	2018	2017
		(In thousands)	
Oil derivatives			
Net gain (loss) on settlements	($11,188)	($27,510)	($9,067)
Net gain (loss) on fair value adjustments	(62,125)	72,973	(11,426)
Total gain (loss) on oil derivatives	(73,313)	45,463	(20,493)
Natural gas derivatives			
Net gain (loss) on settlements	7,399	238	594
Net gain (loss) on fair value adjustments	1,490	2,843	998
Total gain (loss) on natural gas derivatives	8,889	3,081	1,592
Contingent consideration arrangements			
Net gain (loss) on fair value adjustments	2,315	—	—
Total gain (loss) on derivative contracts	($62,109)	$48,544	($18,901)

Derivative positions

Listed in the tables below are the outstanding oil and natural gas derivative contracts as of December 31, 2019:

	For the Full Year of 2020	For the Full Year of 2021
Oil contracts (WTI)		
Collar contracts with short puts (three-way collars)		
Total volume (Bbls)	13,176,000	—
Weighted average price per Bbl		
Ceiling (short call)	$65.28	$ —
Floor (long put)	$55.38	$ —
Floor (short put)	$45.08	$ —
Short call contracts		
Total volume (Bbls)	1,674,450 (1)	4,825,300 (1)
Weighted average price per Bbl	$75.98	$63.62
Swap contracts		
Total volume (Bbls)	1,303,900	—
Weighted average price per Bbl	$55.19	$—
Swap contracts with short puts		
Total volume (Bbls)	2,196,000	—
Weighted average price per Bbl		
Swap	$56.06	$—
Floor (short put)	$42.50	$—
Oil contracts (Brent ICE)		
Collar contracts with short puts (three-way collars)		
Total volume (Bbls)	837,500	—
Weighted average price per Bbl		
Ceiling (short call)	$70.00	$—
Floor (long put)	$58.24	$—
Floor (short put)	$50.00	$—
Oil contracts (Midland basis differential)		
Swap contracts		
Total volume (Bbls)	8,476,700	4,015,100
Weighted average price per Bbl	($1.47)	$0.40
Oil contracts (Argus Houston MEH basis differential)		
Swap contracts		
Total volume (Bbls)	1,439,205	—
Weighted average price per Bbl	$2.40	$—
Oil contracts (Argus Houston MEH swaps)		
Swap contracts		
Total volume (Bbls)	504,500	—
Weighted average price per Bbl	$58.22	$—
Natural gas contracts (Henry Hub)		
Collar contracts (three-way collars)		
Total volume (MMBtu)	3,660,000	—
Weighted average price per MMBtu		
Ceiling (short call)	$2.75	$—
Floor (long put)	$2.50	$—
Floor (short put)	$2.00	$—
Swap contracts		
Total volume (MMBtu)	3,660,000	—
Weighted average price per MMBtu	$2.48	$—
Short call contracts		
Total volume (MMBtu)	12,078,000	7,300,000
Weighted average price per MMBtu	$3.50	$3.09
Natural gas contracts (Waha basis differential)		
Swap contracts		
Total volume (MMBtu)	21,596,000	—
Weighted average price per MMBtu	($1.04)	$—

(1) Premiums from the sale of call options were used to increase the fixed price of certain simultaneously executed price swaps and three-way collars.

Note 9 – Fair Value Measurements

Accounting guidelines for measuring fair value establish a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

Level 1 – Observable inputs such as quoted prices in active markets at the measurement date for identical, unrestricted assets or liabilities.

Level 2 – Other inputs that are observable directly or indirectly such as 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.

Level 3 – Unobservable inputs for which there is little or no market data and which the Company makes its own assumptions about how market participants would price the assets and liabilities.

Fair value of financial instruments

Cash, cash equivalents, and restricted investments. The carrying amounts for these instruments approximate fair value due to the short-term nature or maturity of the instruments.

Debt. The carrying amount of borrowings outstanding under the Credit Facility approximate fair value as the borrowings bear interest at variable rates and are reflective of market rates. The following table presents the principal amounts of the Company's senior notes with the fair values measured using quoted secondary market trading prices which are designated as Level 2 within the valuation hierarchy. See "Note 7 - Borrowings" for further discussion.

	2019		2018	
	Principal Amount	Fair Value	Principal Amount	Fair Value
		(In thousands)		
6.25% Senior Notes	$650,000	$658,125	$—	$—
6.125% Senior Notes	600,000	611,130	600,000	558,000
8.25% Senior Notes	250,000	256,250	—	—
6.375% Senior Notes	400,000	405,424	400,000	372,000
Total	$1,900,000	$1,930,929	$1,000,000	$930,000

Assets and liabilities measured at fair value on a recurring basis

Certain assets and liabilities are reported at fair value on a recurring basis in the consolidated balance sheet. The following methods and assumptions were used to estimate fair value:

Commodity derivative instruments. The fair value of commodity derivative instruments is derived using a third-party income approach valuation model that utilizes market-corroborated inputs that are observable over the term of the commodity derivative contract. The Company's fair value calculations also incorporate an estimate of the counterparties' default risk for commodity derivative assets and an estimate of the Company's default risk for commodity derivative liabilities. As the inputs in the model are substantially observable over the term of the commodity derivative contract and there is a wide availability of quoted market prices for similar commodity derivative contracts, the Company designates its commodity derivative instruments as Level 2 within the fair value hierarchy. See "Note 8 - Derivative Instruments and Hedging Activities" for further discussion.

Contingent consideration arrangements - embedded derivative financial instruments. The embedded options within the contingent consideration arrangements are considered financial instruments under ASC 815. The Company engages a third-party valuation specialist using an option pricing model approach to measure the fair value of the embedded options on a recurring basis. The valuation includes significant inputs such as forward oil price curves, time to expiration, and implied volatility. The model provides for the probability that the specified pricing thresholds would be met for each settlement period, estimates undiscounted payouts, and risk adjusts for the discount rates inclusive of adjustments for each of the counterparty's credit quality. As these inputs are substantially observable for the full term of the contingent consideration arrangements, the inputs are considered Level 2 inputs within the fair value hierarchy. See "Note 8 - Derivative Instruments and Hedging Activities" for further discussion.

The following tables present the Company's assets and liabilities measured at fair value on a recurring basis as of December 31, 2019 and 2018:

	December 31, 2019		
	Level 1	Level 2	Level 3
		(In thousands)	
Assets			
Commodity derivative instruments	$—	$9,338	$—
Contingent consideration arrangements	—	25,934	—
Liabilities			
Commodity derivative instruments	—	(34,132)	—
Contingent consideration arrangements	—	(69,760)	—
Total net assets (liabilities)	$—	($68,620)	$—

	December 31, 2018		
	Level 1	Level 2	Level 3
		(In thousands)	
Assets			
Commodity derivative instruments	$—	$65,114	$—
Liabilities			
Commodity derivative instruments	—	(17,920)	—
Total net liabilities (liabilities)	$—	$47,194	$—

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Acquisitions. The fair value of assets acquired and liabilities assumed, other than the contingent consideration arrangements which are discussed above, are measured as of the acquisition date by a third-party valuation specialist using the income approach based on inputs that are not observable in the market and are therefore designated as Level 3 inputs. Significant inputs include expected discounted future cash flows from estimated reserve quantities, estimates for timing and costs to produce and develop reserves, oil and natural gas forward prices, and a risk adjusted discount rate. See "Note 4 - Acquisitions and Divestitures" for additional discussion.

Asset retirement obligations. The Company measures the fair value of asset retirement obligations as of the date a well begins drilling or when production equipment and facilities are installed using a discounted cash flow model based on inputs that are not observable in the market and therefore are designated as Level 3 within the valuation hierarchy. Significant inputs to the fair value measurement of asset retirement obligations include estimates of the costs of plugging and abandoning oil and gas wells, removing production equipment and facilities and restoring the surface of the land as well as estimates of the economic lives of the oil and gas wells and future inflation rates. See "Note 14 - Asset Retirement Obligations" for additional discussion.

Note 10 – Share-Based Compensation

2018 Omnibus Incentive Plan

The 2018 Omnibus Incentive Plan, which became effective May 10, 2018 following shareholder approval (the "2018 Plan"), authorized and reserved for issuance 9,400,000 shares of common stock, which may be issued upon exercise of vested stock options and/or the vesting of any other share-based equity award that is granted under this plan. The 2018 Plan replaced the 2011 Omnibus Incentive Plan (the "Prior Plan"), and included a provision at inception whereby all remaining, un-issued and authorized shares from the Prior Plan became issuable under the 2018 Plan. This transfer provision resulted in the transfer of an additional 1,322,742 shares into the 2018 Plan, increasing the quantity authorized and reserved for issuance under the 2018 Plan to 10,722,742 at the inception of the 2018 Plan. Another provision provided that shares, which would otherwise become available for issuance under the Prior Plan as a result of vesting and/or forfeiture of any equity awards existing as of the effective date of the 2018 Plan, would also increase the authorized shares available to the 2018 Plan. As a result of the Merger, the 2018 Plan was amended and restated to incorporate the 2017 Incentive Plan of Carrizo Oil & Gas, Inc. (the "Carrizo Plan"), including outstanding awards under the Carrizo Plan and shares available to grant to the former employees of Carrizo which were converted to shares of the Company by applying the conversion ratio of 1.75 shares of the Company per one share of Carrizo (the "Amended and Restated 2018 Plan"). At December 31, 2019, there were 13,814,216 shares available for future share-based awards under the Amended and Restated 2018 Plan.

RSU Equity Awards

The following table summarizes RSU Equity Award activity for the years ended December 31, 2019, 2018 and 2017:

	RSU Equity Awards (in thousands)	Weighted Average Grant-Date Fair Value per Share
For the Year Ended December 31, 2017		
Unvested at the beginning of the period	1,448	$10.81
Granted (1) (2)	1,173	$12.25
Vested (3)	(797)	$11.35
Forfeited	(34)	$9.57
Unvested at the end of the period	1,790	$11.54
For the Year Ended December 31, 2018		
Unvested at the beginning of the period	1,790	$11.54
Granted (1)	872	$13.89
Vested (3)	(506)	$9.56
Forfeited	(53)	$11.43
Unvested at the end of the period	2,103	$13.24
For the Year Ended December 31, 2019		
Unvested at the beginning of the period	2,103	$13.24
Granted (1)	1,881	$8.60
Vested (3)	(1,062)	$12.35
Forfeited	(227)	$10.59
Unvested at the end of the period	2,695	$10.57

(1) Includes 399,425, 208,000 and 89,000 target performance-based RSU Equity Awards that will vest at a range of 0% - 200% for the years ended December 31, 2019, 2018 and 2017, respectively.

(2) Includes 73,000 performance based RSU Equity Awards that were granted and subsequently vested at 142% of target at issuance in 2017.

(3) The fair value of shares vested was $7.3 million, $6.3 million and $9.0 million during the years ended December 31, 2019, 2018 and 2017, respectively.

Performance-based RSU Equity Awards that vest are based on a calculation that compares the Company's total shareholder return to the same calculated return of a group of peer companies as selected by the Company, and the number of units that will vest can range between 0% and 200% of the base units awarded. The following table summarizes the shares that vested and did not vest as a result of the Company's performance as compared to its peers.

	Years Ended December 31,		
Performance-based Equity Awards	**2019**	**2018**	**2017**
Vesting Multiplier	100%	142%	142% - 200%
Target	88,790	83,002	258,406
Vested at end of performance period	88,790	117,862	441,232
Did not vest at end of performance period	—	—	—

The Company recognizes expense for performance-based RSU Equity Awards based on the fair value of the awards at the grant date. Awards with a performance-based provision do not allow for the reversal of previously recognized expense, even if the market metric is not achieved and no shares ultimately vest. For the years ended December 31, 2019, 2018 and 2017, the grant date fair value of the performance-based RSU Equity Awards, calculated using a Monte Carlo simulation, was $4.3 million, $3.5 million, and $2.6 million, respectively. The following table summarizes the assumptions used and the resulting grant date fair value per performance-based RSU Equity Award granted during the years ended December 31, 2019, 2018 and 2017:

	Years Ended December 31,		
Performance-based Awards	**2019**	**2018**	**2017**
Number of simulations	100,000	100,000	100,000
Expected term (in years)	2.9	2.6	2.6
Expected volatility	47.9%	51.6%	65.3%
Risk-free interest rate	2.4%	2.6%	1.5%
Dividend yield	—%	—%	—%
Grant date fair value per performance-based RSU Equity Award	$10.78	$16.66	$16.06

As of December 31, 2019, unrecognized compensation costs related to unvested RSU Equity Awards were $15.1 million and will be recognized over a weighted average period of 1.3 years.

***Cash-Settled RSU* Awards**

The table below summarizes the Cash-Settled RSU Award activity for the years ended December 31, 2019, 2018 and 2017:

	Cash-Settled RSU Awards (in thousands)	Weighted Average Grant-Date Fair Value per Share
For the Year Ended December 31, 2017		
Unvested at the beginning of the period	734	$8.87
Granted	283	$12.13
Vested	(379)	$9.61
Forfeited	(13)	$9.54
Unvested at the end of the period	625	$9.88
For the Year Ended December 31, 2018		
Unvested at the beginning of the period	625	$9.88
Granted	348	$14.16
Vested	(276)	$9.04
Forfeited	(19)	$12.05
Unvested at the end of the period	678	$12.36
For the Year Ended December 31, 2019		
Unvested at the beginning of the period	678	$12.36
Granted	424	$8.14
Vested	(164)	$12.02
Forfeited	(83)	$11.58
Unvested at the end of the period	855	$10.41

All of the Company's outstanding Cash-Settled RSU Awards include a performance-based vesting condition that determines the actual number of units that will ultimately vest. The number of Cash-Settled RSU Awards that vest is based on a calculation that compares the Company's total shareholder return to the same calculated return of a group of peer companies as selected by the Company, and the number of units that will vest can range between 0% and 200% of the base units awarded.

For the year ended December 31, 2019, 147,492 performance-based Cash-Settled RSU Awards vested at 100% of their issued units, resulting in a payable amount of $0.7 million in 2020. Also during 2019, 16,600 non-performance-based Cash-Settled RSU Awards vested, resulting in cash payments of $0.1 million in 2019.

For the year ended December 31, 2018, 207,261 performance-based Cash-Settled RSU Awards subject to the peer performance-based vesting described above, vested between 100% to 163% of their issued units, depending on the date of the vesting, resulting in cash payments of $0.1 million in 2018 and $1.3 million in 2019. Also during 2018, 129,753 non-performance-based Cash-Settled RSU Awards vested, resulting in cash payments of $1.8 million during 2018.

The following table summarizes the Company's liability for Cash-Settled RSU Awards and the classification in the consolidated balance sheets for the periods indicated:

	December 31,	
	2019	2018
Other current liabilities	$966	$1,390
Other long-term liabilities	2,089	2,067
Total Cash-Settled RSU Awards	$3,055	$3,457

As of December 31, 2019, the Company had the following performance-based Cash-Settled RSU Awards outstanding:

	Target Awards Outstanding	Potential Minimum Units Vesting	Potential Maximum Units Vesting
		(In thousands)	
Vesting in 2020	292	—	586
Vesting in 2021	373	—	745
Vesting in 2022	—	—	—
Other	24	24	24
Total Cash-Settled RSU Awards	689	24	1,355

As of December 31, 2019, unrecognized compensation costs related to unvested Cash-Settled RSU Awards were $1.1 million and will be recognized over a weighted average period of 1.5 years.

Cash-Settled SARs

As a result of the Merger, Cash SARs previously granted by Carrizo that were outstanding at closing of the Merger were canceled and converted into a Cash SAR covering shares of the Company's common stock, with the conversion calculated as prescribed in the agreement governing the Merger. The table below summarizes the Cash SAR activity for the year ended December 31, 2019.

	Stock Appreciation Rights	Weighted Average Exercise Prices	Weighted Average Remaining Life (In years)	Aggregate Intrinsic Value (In millions)
For the Year Ended December 31, 2019				
Outstanding, beginning of period	—	$—		
Granted	—	$—		
Reissued	3,677,955	$10.03		
Exercised	—	$—		
Forfeited	—	$—		
Expired	—	$—		
Outstanding, end of period	3,677,955	$10.03	4.4	$—
Vested, end of period	3,677,955	$10.03	0	$—
Vested and exercisable, end of period	—	$—	0	$—

The acquisition date fair value of the Cash SARs, calculated using the Black-Scholes-Merton option pricing model was $4.6 million. The following table summarizes the assumptions used, the resulting acquisition date fair value per Cash SAR, and the expiration dates for the grants that occurred during periods presented below:

	2019	2018	2017	2016
Fair Value Inputs				
Expected term (in years)	5.4	4.5	1.9	1.1
Expected volatility	60.7%	56.9%	58.6%	68.1%
Risk-free interest rate	1.7%	1.7%	1.6%	1.5%
Dividend yield	—%	—%	—%	—%
Acquisition date fair value per Cash SAR	$2.11	$1.42	$0.21	$0.10
Expiration date	March 17, 2026	March 17, 2025	March 23, 2022	March 17, 2021

The liability for Cash SARs as of December 31, 2019 was $5.0 million, all of which was classified as "Other current liabilities" in the consolidated balance sheets in the respective period. Changes to the fair value of the Cash SARs are included in "General and administrative" in the consolidated statements of operations. As all Cash SARs are vested, there is no unrecognized compensation costs as of December 31, 2019.

Share-Based Compensation Expense, Net

The following table presents share-based compensation expense for each respective period:

	Years Ended December 31,					
	2019		**2018**		**2017**	
Share-based compensation cost for:	Equity	Liability	Equity	Liability	Equity	Liability
RSU Equity Awards (1)	$14,322	$—	$9,460	$—	$10,225	$—
Cash-Settled RSU Awards (1)	—	1,021	—	336	—	4,294
Cash SARs	—	443	—	—	—	—
Total share-based compensation cost (2)	$14,322	$1,464	$9,460	$336	$10,225	$4,294

(1) Includes the settlement of the outstanding share-based award agreements of the Company's former Chief Executive Officer, resulting in $6.4 million recorded on the consolidated statements of operations as settled share-based awards for the year ended December 31, 2017.

(2) The portion of this share-based compensation cost that was included in "General and administrative" totaled $11.1 million, $6.4 million and $5.0 million for the years ended December 31, 2019, 2018 and 2017, respectively, and the portion capitalized to oil and gas properties was $4.7 million, $3.4 million and $3.2 million for the years ended December 31, 2019, 2018, and 2017, respectively.

Note 11 – Stockholders' Equity

Increase in Authorized Common Shares

As a result of the Carrizo Acquisition, the shareholders approved an amendment to the Company's Certificate of Incorporation to increase the number of authorized shares of common stock from 300,000,000 to 525,000,000.

10% Series A Cumulative Preferred Stock ("Preferred Stock")

Holders of the Company's Preferred Stock were entitled to receive, when, as and if declared by the Company's board of directors, out of funds legally available for the payment of dividends, cumulative cash dividends at a rate of 10% per annum of the $50.00 liquidation preference per share (equivalent to $5.00 per annum per share). Dividends were payable quarterly in arrears on the last day of each March, June, September and December when, as and if declared by the Board of Directors. Preferred Stock dividends were $4.0 million, $7.3 million and $7.3 million for years ended December 31, 2019, 2018 and 2017, respectively.

On June 18, 2019, the Company announced it had given notice for the redemption (the "Redemption") of all outstanding shares of the Preferred Stock. On July 18, 2019 (the "Redemption Date"), the Preferred Stock were redeemed at a redemption price equal to $50.00 per share, plus an amount equal to all accrued and unpaid dividends in an amount equal to $0.24 per share, for a total redemption price of $50.24 per share or $73.0 million (the "Redemption Price"). The Company recognized an $8.3 million loss on the redemption due to the excess of the $73.0 million redemption price over the $64.7 million redemption date carrying value of the Preferred Stock.

After the Redemption Date, the Preferred Stock were no longer deemed outstanding, dividends on the Preferred Stock ceased to accrue, and all rights of the holders with respect to such Preferred Stock were terminated, except the right of the holders to receive the Redemption Price, without interest.

Common Stock Offerings

On May 30, 2018, the Company completed an underwritten public offering of 25.3 million shares of its common stock for total estimated net proceeds (after the underwriter's discounts and offering costs) of approximately $288.0 million. The Company used proceeds from the offering to partially fund the Delaware Asset Acquisition completed in the third quarter of 2018. See "Note 4 - Acquisitions and Divestitures" for further discussion of the Delaware Asset Acquisition.

On December 19, 2016, the Company completed an underwritten public offering of 40.0 million shares of its common stock for total estimated net proceeds (after the underwriter's discounts and estimated offering expenses) of approximately $634.9 million. Proceeds from the offering were used to partially fund the Ameredev Acquisition. See "Note 4 - Acquisitions and Divestitures" for further discussion of the Ameredev Acquisition.

Note 12 – Income Taxes

The components of the Company's income tax expense are as follows:

	Years Ended December 31,		
	2019	2018	2017
	(In thousands)		
Current			
Federal	$—	$—	($48)
State	220	—	—
Total current income tax expense (benefit)	220	—	(48)
Deferred			
Federal	33,584	3,594	(45)
State	1,497	4,516	1,366
Total deferred income tax expense	35,081	8,110	1,321
Total income tax expense	$35,301	$8,110	$1,273

A reconciliation of the income tax expense calculated at the federal statutory rate of 21% in 2019 and 2018 and 35% in 2017, to income tax expense is as follows:

	Years Ended December 31,		
	2019	2018	2017
Income before income taxes	$103,229	$308,470	$121,697
Income tax expense computed at the statutory federal income tax rate	21,678	64,779	42,594
State income tax expense, net of federal benefit	1,253	3,568	1,273
Equity based compensation	1,222	(494)	—
Non-deductible compensation	90	1,209	—
Non-deductible merger expenses	5,537	—	—
Statutory depletion carryforward	5,381	—	—
Other	140	168	—
Change in valuation allowance	—	(61,120)	(42,594)
Income tax expense	$35,301	$8,110	$1,273

At December 31, 2019, the Company recorded a tax expense of $5.5 million associated with non-deductible merger expenses from the Carrizo Acquisition which primarily relate to non-deductible executive compensation expenses and transaction costs that are inherently facilitative in nature and permanently capitalized for tax purposes.

The Company recorded an income tax expense of $5.4 million related to the statutory depletion carryforward of $24.9 million. The percentage depletion deductions are in excess of the Company's net depletable basis and can be carried forward indefinitely. The tax benefit for the special deduction will be recognized in the year the carryforward is deducted on the federal tax return.

As of December 31, 2019 and 2018, the net deferred income tax assets and liabilities are comprised of the following:

	As of December 31,	
	2019	2018
	(In thousands)	
Deferred tax assets		
Federal net operating loss carryforward	$110,703	$151,497
Interest expense carryforward	—	7,335
Statutory depletion carryforward	—	5,381
Asset retirement obligations	9,981	2,347
Derivative asset	14,823	—
Unvested RSU equity awards	4,928	2,751
Operating lease right-of-use assets	29,897	—
Other	10,445	991
Total deferred tax assets	$180,777	$170,302
Deferred income tax valuation allowance	—	—
Net deferred tax assets	$180,777	$170,302
Deferred tax liability		
Oil and natural gas properties	($38,546)	($169,682)
Derivative liability	—	(10,184)
Operating lease liabilities	(26,511)	—
Total deferred tax liability	($65,057)	($179,866)
Net deferred tax asset (liability)	$115,720	($9,564)

For federal income tax purposes, the Carrizo Acquisition qualified as a tax-free merger whereby the Company acquired carryover tax basis in Carrizo's assets and liabilities. The Company recorded an opening balance sheet deferred tax asset of $159.3 million related to tax attributes acquired from Carrizo. The acquired income tax attributes primarily consist of future deductions related to oil and gas properties, derivative assets, and federal net operating losses ("NOLs"). The acquired NOLs are subject to an annual limitation under Internal Revenue Code Section 382 and the Company reduced the total NOL balance and associated deferred tax asset for the NOLs to the amount expected to be fully utilized prior to expirations. The Company expects that these tax attributes will be fully utilized prior to expiration.

Due to the issuance of common stock associated with the Carrizo acquisition, the Company incurred a cumulative ownership change and as such, the Company's NOLs prior to the acquisition are subject to an annual limitation under Internal Revenue Code Section 382. At December 31, 2019, the Company had approximately $527.2 million of NOLs, including $288.2 million acquired from Carrizo, of which approximately $496.5 million expire between 2035 and 2037 and $30.7 million have an indefinite carryforward life. The Company expects that the NOL balance 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 net deferred tax assets will be utilized prior to their expiration. At December 31, 2019, 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 and determined that it is more likely than not that the Company will realize its remaining deferred tax assets.

The Company had no significant unrecognized tax benefits at December 31, 2019. Accordingly, the Company does not have any interest or penalties related to uncertain tax positions. However, if interest or penalties were to be incurred related to uncertain tax positions, such amounts would be recognized in income tax expense. In the Company's major tax jurisdictions, the earliest year open to examination is 2015.

Note 13 – Leases

The Company determines if an arrangement is a lease at inception of the contract and, if the contract is determined to be a lease, classifies the lease as an operating or financing lease. The Company recognizes an operating or financing lease on its consolidated balance sheets as a lease liability, which represents the present value of the Company's obligation to make lease payments arising from the lease, with a related ROU asset, which represents the Company's right to use the underlying asset for the lease term. The Company's operating leases typically do not provide an implicit interest rate, therefore, the Company utilizes its incremental borrowing rate to calculate the present value of the lease payments based on information available at inception of the contract.

Lease expense for operating leases is recognized on a straight-line basis over the lease term. Lease expense for financing leases is comprised of interest expense on the financing lease liability and the amortization of the associated ROU asset, which is recognized on a straight-line basis over the lease term. Variable lease expense that is not dependent on an index or rate is not included in the operating or financing lease liability or ROU asset and is recognized in the period in which the obligation for those payments is incurred.

Types of Leases

The Company currently has leases associated with contracts for drilling rigs, office space, and the use of well equipment, vehicles, information technology infrastructure, and other office equipment, with the significant lease types described in more detail below.

Drilling Rigs. The Company enters into contracts for drilling rigs with third parties to support its development plan. These contracts are typically for one to three years and can be extended upon mutual agreement with the third party by providing written notice at least thirty days prior to the end of the primary contractual term. The Company exercises its discretion in choosing whether or not to extend these contracts on a drilling rig by drilling rig basis as a result of evaluating the conditions that exist at the time the contract expires, such as availability of drilling rigs and the Company's development plan. The Company has determined that it cannot conclude with reasonable certainty that it will choose to extend the contract past its primary term. As such, the Company uses the primary term in its calculation of the lease liability and ROU asset. The Company classifies its drilling rigs as operating leases and capitalizes the costs of the drilling rigs to oil and gas properties.

Office Space. The Company leases office space from third parties for its corporate office and certain field locations. These leases have non-cancelable terms between one to fifteen years. The Company has determined that it cannot conclude with reasonable certainty that it will exercise any option to extend the contract past the non-cancelable term. As such, the Company uses the non-cancelable term in its calculation of the lease liability and ROU asset. The Company classifies its leases for office space as operating leases with the costs recognized as "General and administrative" in its consolidated statements of operations.

Well Equipment. The Company rents compressors from third parties to facilitate the flow of production from its drilling operations to market. These contracts range from less than one year to three years for the primary term and continue thereafter on a month to month basis subject to cancellation by either party with thirty days' notice. The Company classifies the compressors as operating leases with a lease term equal to the primary term for those contracts that have a primary term greater than one year. After the primary term, each party has a substantive right to terminate the lease, therefore, enforceable rights and obligations do not exist subsequent to the primary term. For those contracts that are less than one year, the Company has concluded that they represent short-term operating leases and therefore, an operating lease liability and ROU asset is not recorded in the consolidated balance sheets. These lease payments are recognized as "Lease operating" in the Company's statements of operations.

The tables below, which present the components of lease costs and supplemental balance sheet information are presented on a gross basis. Other joint owners in the properties operated by the Company generally pay for their working interest share of costs associated with drilling rigs and well equipment.

The table below presents the components of the Company's lease costs for the year ended December 31, 2019.

	Year Ended December 31, 2019
	(In thousands)
Components of Lease Costs	
Finance lease costs	$92
Amortization of right-of-use assets (1)	82
Interest on lease liabilities (2)	10
Operating lease cost (3)	38,076
Impairment of Operating lease ROU assets (4)	16,209
Short-term lease cost (5)	3,640
Variable lease costs (6)	—
Total lease costs	$58,017

(1) Included as a component of "Depreciation, depletion and amortization" in the consolidated statements of operations.
(2) Included as a component of "Interest expense, net of capitalized amounts" in the consolidated statements of operations.
(3) For the year ended December 31, 2019, approximately $34.9 million are costs associated with drilling rigs and are capitalized to "Evaluated properties, net" in the consolidated balance sheets and the other remaining operating lease costs are components of "General and administrative" and "Lease operating" in the consolidated statements of operations.
(4) In conjunction with the Carrizo Acquisition, the Company evaluated certain of its office leases for impairment as the determination was made in 2019 that certain corporate offices would be consolidated. Upon evaluation, the Company recorded an impairment of certain of its Operating lease ROU assets of $16.2 million which is a component of "Merger and integration expenses" in the consolidated statements of operations.
(5) Short-term lease cost excludes expenses related to leases with a contract term of one month or less.
(6) Variable lease costs include additional payments that were not included in the initial measurement of the lease liability and related ROU asset for lease agreements with terms greater than 12 months. Variable lease costs primarily consist of incremental usage associated with drilling rigs.

The table below presents supplemental balance sheet information for the Company's leases as of December 31, 2019.

	Year Ended December 31, 2019 (In thousands)
Leases	
Operating leases:	
Operating lease ROU assets	$63,908
Current operating lease liabilities	$42,858
Long-term operating lease liabilities	37,088
Total operating lease liabilities	79,946
Financing leases:	
Other property and equipment	$2,197
Accumulated depreciation	(82)
Other property and equipment, net	2,115
Current financing lease liabilities	$1,334
Long-term financing lease liabilities	807
Total financing lease liabilities	2,141

The table below presents the weighted average remaining lease terms and weighted average discounts rates for the Company's leases as of December 31, 2019.

	December 31, 2019
Weighted Average Remaining Lease Terms (In years)	
Operating leases	4.3
Financing leases	2.1
Weighted Average Discount Rate	
Operating leases	5.5%
Financing leases	9.4%

The table below presents the maturity of the Company's lease liabilities as of December 31, 2019.

	Operating Leases	Financing Leases
	(In thousands)	
2020	$45,864	$1,475
2021	11,648	275
2022	4,363	234
2023	4,209	233
2024	4,110	38
Thereafter	17,902	—
Total lease payments	88,096	2,255
Less imputed interest	8,150	114
Total lease liabilities	$79,946	$2,141

Note 14 – Asset Retirement Obligations

The table below summarizes the activity for the Company's asset retirement obligations:

	Years Ended December 31,	
	2019	2018
	(In thousands)	
Asset retirement obligations, beginning of period	$14,292	$6,020
Accretion expense	945	874
Liabilities incurred	615	973
Increase due to acquisition of oil and gas properties	26,107	570
Liabilities settled	(3,394)	(1,288)
Dispositions	(1,776)	(614)
Revisions to estimates	12,944	7,757
Asset retirement obligations, end of period	49,733	14,292
Less: Current asset retirement obligations	(873)	(3,887)
Non-current asset retirement obligations	$48,860	$10,405

Certain of the Company's operating agreements require that assets be restricted for future abandonment obligations. Amounts recorded on the consolidated balance sheets at December 31, 2019 and 2018 as long-term restricted investments were $3.5 million and $3.4 million, respectively, and are presented in "Other assets, net." These assets, which primarily include short-term U.S. Government securities, are held in abandonment trusts dedicated to pay future abandonment costs for several of the Company's oil and natural gas properties.

Note 15 – Accounts Receivable, Net

	As of December 31,	
	2019	2018
	(In thousands)	
Oil and natural gas receivables	$165,275	$87,062
Joint interest receivables	42,493	42,373
Other receivables	3,231	3,150
Total	210,999	132,585
Allowance for doubtful accounts	(1,536)	(865)
Total accounts receivable, net	$209,463	$131,720

Note 16 – Accounts Payable and Accrued Liabilities

	As of December 31,	
	2019	2018
	(In thousands)	
Accounts payable	$238,758	$83,412
Revenues payable	145,816	94,114
Accrued capital expenditures	61,950	83,658
Accrued interest	36,295	24,665
Accrued severance [(1)]	28,803	—
Total accounts payable and accrued liabilities	$511,622	$285,849

(1) See "Note 4 - Acquisitions and Divestitures" for further information regarding the Carrizo Acquisition.

Note 17 – Commitments and Contingencies

The Company is involved in various claims and lawsuits incidental to its business. In the opinion of management, the ultimate liability hereunder, if any, will not have a material adverse effect on the financial position or results of operations of the Company.

The Company's activities are subject to federal, state and local laws and regulations governing environmental quality and pollution control. Although no assurances can be made, the Company believes that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, rules and regulations governing the release of materials into the environment or otherwise relating to the protection of the environment are not expected to have a material effect upon the capital expenditures, earnings or the competitive position of the Company with respect to its existing assets and operations. The Company cannot predict what effect additional regulation or legislation, enforcement policies hereunder, and claims for damages to property, employees, other persons and the environment resulting from the Company's operations could have on its activities. The table below presents total minimum commitments associated with long-term, non-cancelable leases, drilling rig contracts and gathering, processing and transportation service agreements, which require minimum volumes of natural gas or produced water to be delivered, as of December 31, 2019.

	2020	2021	2022	2023	2024	2025 and Thereafter	Total
				(In thousands)			
Operating leases	$12,423	$8,399	$4,363	$4,209	$4,110	$17,902	$51,406
Drilling rig contracts (1)	33,441	3,249	—	—	—	—	36,690
Delivery commitments (2)	9,563	13,437	10,980	11,553	12,417	39,298	97,248
Produced water disposal commitments (3)	14,947	14,968	11,933	4,387	1,570	1,840	49,645
Total	$70,374	$40,053	$27,276	$20,149	$18,097	$59,040	$234,989

(1) Drilling rig contracts represent gross contractual obligations and accordingly, other joint owners in the properties operated by the Company will generally be billed for their working interest share of such costs.
(2) Delivery commitments represent contractual obligations we have entered into for certain gathering, processing and transportation service agreements which require minimum volumes of natural gas to be delivered. The amounts in the table above reflect the aggregate undiscounted deficiency fees assuming no delivery of any natural gas.
(3) Produced water disposal commitments represent contractual obligations we have entered into for certain service agreements which require minimum volumes of produced water to be delivered. The amounts in the table above reflect the aggregate undiscounted deficiency fees assuming no delivery of any produced water.

Operating leases

As of December 31, 2019, the Company had contracts for nine horizontal drilling rigs. The contract terms will end on various dates between January 2020 and May 2021.

Other commitments

In July 2019, the Company executed a crude oil sales contact that provides dedicated capacity on a new pipeline system that originates in Midland County, Texas and will have delivery points in several locations along the Gulf Coast. The Company will have a long-term 5,000 Bbls per day commitment for the term of the agreement and will apply applicable tariff rates to those quantities. Barrels may include volumes produced by the Company and other third-party working, royalty, and overriding royalty interest owners whose volumes we market on their behalf.

In June 2019, the Company executed a firm transportation agreement for dedicated capacity on a new pipeline system that originates in Midland, Texas and terminates in Houston, Texas. Subject to completion of the new pipeline system, which will have delivery points in several locations along the Gulf Coast, the Company will have a long-term commitment that will apply applicable tariff rates to our quantities committed that average 10,000 Bbls per day for the term of the agreement. Barrels may be transported to multiple delivery points along the Gulf Coast and may include volumes produced by the Company and other third-party working, royalty, and overriding royalty interest owners whose volumes we market on their behalf.

In January 2019, the Company executed a crude oil sales contract that provides further dedicated capacity on several pipeline systems that will connect with a regional gathering system which currently transports oil volumes under long-term agreements from our properties in Howard and Ward Counties, Texas and will have delivery points in several locations along the Gulf Coast, providing the Company with the potential benefit of access to an international weighted average sales price. The Company will have a long-term 10,000 Bbls per day commitment for the term of the agreement, and may include volumes produced by the Company and other third-party working, royalty, and overriding royalty interest owners whose volumes we market on their behalf.

In August 2018, the Company executed a firm transportation agreement for dedicated capacity on a new pipeline system that will connect with a regional gathering system which currently transports oil volumes under long-term agreements from our properties in Howard and Ward Counties, Texas to multiple marketing points in the Permian Basin. Subject to completion of the new pipeline system, which will have delivery points in several locations along the Gulf Coast, the Company will have a long-term commitment that will apply applicable tariff rates to our 15,000 Bbls per day commitment for the term of the agreement. Barrels may be transported to multiple delivery points along the Gulf Coast and may include volumes produced by the Company and other third-party working, royalty, and overriding royalty interest owners whose volumes we market on their behalf.

In March 2018, the Company entered into a contract for dedicated fracturing and pump down perforating crews, which was effective on April 16, 2018 for a two-year period. The agreement was amended effective October 16, 2018 to reflect updated market conditions and to extend the contract expiration date to December 31, 2021.

Note 18 – Subsequent Events (Unaudited)

Contingent Consideration Arrangements

For the year ended December 31, 2019, the specified pricing thresholds related certain of the contingent consideration arrangements acquired in the Carrizo Acquisition were exceeded. As a result, in January 2020, the Company paid $50.0 million and received $10.0 million from settlement of a portion of these contingent consideration arrangements.

Note 19 - Supplemental Information on Oil and Natural Gas Operations (Unaudited)

Estimated Reserves

The estimated proved reserves obtained as a result of the Carrizo Acquisition were prepared by Ryder Scott Company, L.P. ("Ryder Scott"), the independent third party reserve engineers historically retained by Carrizo. All other estimated proved reserves for each respective year were prepared by DeGolyer and MacNaughton ("D&M"), Callon's independent third party reserve engineers (together with Ryder Scott, the "Reserve Engineering Firms"). The reserves were prepared in accordance with guidelines established by the SEC. Accordingly, the following reserve estimates are based upon existing economic and operating conditions.

There are numerous uncertainties inherent in establishing quantities of proved reserves. The following reserve data represents estimates only, and should not be deemed exact. In addition, the standardized measure of discounted future net cash flows should not be construed as the current market value of the Company's oil and natural gas properties or the cost that would be incurred to obtain equivalent reserves.

Extrapolation of performance history and material balance estimates were utilized by the Company's Reserve Engineering Firms to project future recoverable reserves for the producing properties where sufficient history existed to suggest performance trends and where these methods were applicable to the subject reservoirs. The projections for the remaining producing properties were necessarily based on volumetric calculations and/or analogy to nearby producing completions. Reserves assigned to nonproducing zones and undeveloped locations were projected on the basis of volumetric calculations and analogy to nearby production, and to a small extent, horizontal PDP and PUD categories.

The following tables disclose changes in the estimated quantities of proved reserves, all of which are located onshore within the continental United States:

	Years Ended December 31,		
Proved reserves	**2019**	**2018**	**2017**
Oil (MBbls)			
Beginning of period	180,097	107,072	71,145
Purchase of reserves in place	183,382	30,756	8,388
Sales of reserves in place	(17,980)	—	—
Extensions and discoveries	45,663	67,763	39,267
Revisions to previous estimates	(33,136)	(16,051)	(5,171)
Production	(11,665)	(9,443)	(6,557)
End of period	346,361	180,097	107,072
Natural Gas (MMcf)			
Beginning of period	350,466	179,410	122,611
Purchase of reserves in place	455,158	53,563	12,711
Sale of reserves in place	(86,856)	—	—
Extensions and discoveries	82,566	103,149	48,648
Revisions to previous estimates	(24,482)	29,791	6,336
Production	(19,718)	(15,447)	(10,896)
End of period	757,134	350,466	179,410
NGLs (MBbls)			
Beginning of period	—	—	—
Purchase of reserves in place	67,597	—	—
Production	(135)	—	—
End of period	67,462	—	—
Total (MBoe)			
Beginning of period	238,508	136,974	91,580
Purchase of reserves in place	326,838	39,683	10,507
Sale of reserves in place	(32,456)	—	—
Extensions and discoveries	59,424	84,955	47,375
Revisions to previous estimates	(37,216)	(11,086)	(4,115)
Production	(15,086)	(12,018)	(8,373)
End of period	540,012	238,508	136,974

Proved developed reserves:	2019	2018	2017
	Years Ended December 31,		
Oil (MBbls)			
Beginning of period	92,202	51,920	32,920
End of period	152,687	92,202	51,920
Natural gas (MMcf)			
Beginning of period	218,417	104,389	61,871
End of period	320,676	218,417	104,389
NGLs (MBbls)			
Beginning of period	—	—	—
End of period	24,844	—	—
Total proved developed reserves (MBoe)			
Beginning of period	128,605	69,318	43,232
End of period	230,977	128,605	69,318
Proved undeveloped reserves			
Oil (MBbls)			
Beginning of period	87,895	55,152	38,225
End of period	193,674	87,895	55,152
Natural gas (MMcf)			
Beginning of period	132,049	75,021	60,740
End of period	436,458	132,049	75,021
NGLs (MBbls)			
Beginning of period	—	—	—
End of period	42,618	—	—
Total proved undeveloped reserves (MBoe)			
Beginning of period	109,903	67,656	48,348
End of period	309,035	109,903	67,656
Total proved reserves			
Oil (MBbls)			
Beginning of period	180,097	107,072	71,145
End of period	346,361	180,097	107,072
Natural gas (MMcf)			
Beginning of period	350,466	179,410	122,611
End of period	757,134	350,466	179,410
NGLs (MBbls)			
Beginning of period	—	—	—
End of period	67,462	—	—
Total proved reserves (MBoe)			
Beginning of period	238,508	136,974	91,580
End of period	540,012	238,508	136,974

Total Proved Reserves

The Company ended 2019 with estimated proved reserves of 540.0 MMBoe, representing a 126% increase over 2018 year-end estimated proved reserves of 238.5 MMBoe. The Company added 386.3 MMBoe primarily from the Carrizo Acquisition completed in the fourth quarter of 2019 and development efforts in the Permian Basin, where it drilled a total of 61 gross (53.7 net) wells. This increase was offset by 2019 production, sales of reserves of 32.5 MMBoe, which are primarily related to the Ranger Divestiture, and negative revisions of previous estimates of 37.2 MMBoe. The negative revisions include 9.8 MMBoe from the reclassifications of PUDs within our optimized our development plans that were moved outside of the five-year development window. The primary driver of these changes in our previous development plan was the Carrizo Acquisition which allowed the Company to reallocate capital across the combined portfolio in an effort to increase capital efficiency and resulting cash flow generation. The remaining negative revisions were primarily from the observed impact of well spacing tests on producing wells and the related impact on reserve estimates as the Company advanced larger scale development concepts across its multi-zone inventory as well as the adverse effect of pricing and other economic factors.

The Company ended 2018 with estimated net proved reserves of 238.5 MMBoe, representing a 74% increase over 2017 year-end estimated net proved reserves of 137.0 MMBoe. The Company added 124.6 MMBoe primarily from the Delaware Asset Acquisition completed third quarter of 2018 and development efforts in the Permian Basin, where it drilled a total of 70 gross (57.5 net) wells. This increase was offset by 2018 production, negative revisions of previous estimates of 2.0 MMBoe primarily related to technical revisions of proved undeveloped reserves, and reclassifications of proved undeveloped reserves of 9.1 MMBoe from 19 PUD locations primarily due to acreage trades and changes in our development plan, including larger pad development concepts and co-development of zones. These changes resulted in the anticipated drilling of PUD locations being moved beyond five years from initial booking.

The Company ended 2017 with estimated net proved reserves of 137.0 MMBoe, representing a 50% increase over 2016 year-end estimated net proved reserves of 91.6 MMBoe. The Company added 57.9 MMBoe primarily from the Company's acquisition and development efforts in the Permian Basin, where it drilled a total of 49 gross (38.2 net) wells. This increase was primarily offset by 2017 production, revisions of previous estimates, and reclassifications of PUD locations from our development and drilling plan. The Company reclassified 13 PUD locations as a result of a change in the Company's development and drilling plans within its operating areas and the removal of certain proved developed vertical well locations.

Capitalized Costs

Capitalized costs related to oil and natural gas production activities with applicable accumulated depreciation, depletion, amortization and impairment are as follows:

	As of December 31,	
	2019	2018
Oil and natural gas properties:	(In thousands)	
Evaluated properties	$7,203,482	$4,585,020
Unevaluated properties	1,986,124	1,404,513
Total oil and natural gas properties	9,189,606	5,989,533
Accumulated depreciation, depletion, amortization and impairment	(2,520,488)	(2,270,675)
Total oil and natural gas properties capitalized	$6,669,118	$3,718,858

Costs Incurred

Costs incurred in oil and natural gas property acquisitions, exploration and development activities are as follows:

	Years Ended December 31,		
	2019	2018	2017
Acquisition costs:		(In thousands)	
Evaluated properties	$49,572	$347,305	$156,340
Unevaluated properties	107,347	466,816	499,295
Development costs	189,259	259,410	148,254
Exploration costs	309,013	323,458	239,453
Total costs incurred	$655,191	$1,396,989	$1,043,342

Standardized Measure

The following tables present the standardized measure of future net cash flows related to estimated proved oil and natural gas reserves together with changes therein, including a reduction for estimated plugging and abandonment costs that are also reflected as a liability on the balance sheet at December 31, 2019. You should not assume that the future net cash flows or the discounted future net cash flows, referred to in the tables below, represent the fair value of our estimated oil and natural gas reserves. Proved reserve estimates and future cash flows are based on the average realized prices for sales of oil, natural gas, and NGLs on the first calendar day of each month during the year. The following average realized prices were used in the calculation of proved reserves and the standardized measure of discounted future net cash flows.

	Years Ended December 31,		
	2019	2018	2017
Oil ($/Bbl) (1)	$53.90	$58.40	$49.48
Natural gas ($/Mcf) (2)	$1.55	$3.64	$3.47
NGLs ($/Bbl)	$15.58	$—	$—

(1) Includes adjustments to reflect all wellhead deductions and premiums on a property-by-property basis, including transportation costs, location differentials and crude quality.

(2) Includes a high Btu content of separator natural gas and adjustments to reflect the Btu content, transportation charges and other fees specific to the individual properties.

Future production and development costs are based on current costs with no escalations. Estimated future cash flows net of future income taxes have been discounted to their present values based on a 10% annual discount rate.

	Standardized Measure For the Year Ended December 31,		
	2019	2018	2017
		(In thousands)	
Future cash inflows	$20,891,469	$11,794,080	$5,920,328
Future costs			
Production	(6,717,088)	(2,923,959)	(1,692,871)
Development and net abandonment	(3,058,861)	(1,429,787)	(680,948)
Future net inflows before income taxes	11,115,520	7,440,334	3,546,509
Future income taxes	(941,768)	(782,470)	(166,985)
Future net cash flows	10,173,752	6,657,864	3,379,524
10% discount factor	(5,222,726)	(3,716,571)	(1,822,842)
Standardized measure of discounted future net cash flows	$4,951,026	$2,941,293	$1,556,682

	Changes in Standardized Measure For the Year Ended December 31,		
	2019	2018	2017
		(In thousands)	
Standardized measure at the beginning of the period	$2,941,293	$1,556,682	$809,832
Sales and transfers, net of production costs	(579,744)	(481,306)	(294,172)
Net change in sales and transfer prices, net of production costs	(387,970)	222,802	176,234
Net change due to purchases of in place reserves	2,975,296	554,697	129,454
Net change due to sales of in place reserves	(303,526)	—	—
Extensions, discoveries, and improved recovery, net of future production and development costs incurred	607,146	1,001,873	635,000
Changes in future development cost	205,398	40,483	(8,148)
Previously estimated development costs incurred	134,037	91,900	45,131
Revisions of quantity estimates	(420,488)	(167,096)	(79,325)
Accretion of discount	314,921	157,676	80,983
Net change in income taxes	(210,641)	(187,841)	(20,073)
Changes in production rates, timing and other	(324,696)	151,423	81,766
Aggregate change	2,009,733	1,384,611	746,850
Standardized measure at the end of period	$4,951,026	$2,941,293	$1,556,682

Note 20 - Supplemental Quarterly Financial Information (Unaudited)

The following is a summary of the unaudited quarterly financial data for the years ended December 31, 2019 and 2018:

2019	First Quarter (2)	Second Quarter (3)	Third Quarter (4)	Fourth Quarter (5)
	(In thousands, except per share amounts)			
Total operating revenues	$153,047	$167,052	$155,378	$196,095
Income from operations	43,225	58,509	52,544	18,380
Net income (loss)	(19,543)	55,180	55,834	(23,543)
Income (loss) available to common stockholders	(21,367)	53,357	47,180	(23,543)
Income (loss) available to common stockholders per common share (1)				
Basic	($0.09)	$0.23	$0.21	($0.09)
Diluted	($0.09)	$0.23	$0.21	($0.09)

2018	First Quarter	Second Quarter (6)	Third Quarter (7)	Fourth Quarter (8)
	(In thousands, except per share amounts)			
Total operating revenues	$127,440	$137,075	$161,214	$161,895
Income from operations	60,986	67,400	72,811	58,333
Net income	55,761	50,474	37,931	156,194
Income available to common stockholders	53,937	48,650	36,108	154,370
Income available to common stockholders per common share (1)				
Basic	$0.27	$0.23	$0.16	$0.68
Diluted	$0.27	$0.23	$0.16	$0.68

(1) The sum of quarterly income (loss) available to common stockholders per common share does not agree with the total year income (loss) available to common stockholders per common share as each computation is based on the weighted average of common shares outstanding during the period.

(2) First quarter of 2019 included the following:

a. $67.3 million loss on derivative contracts

(3) Second quarter of 2019 included the following:

a. $14.0 million gain on derivative contracts

(4) Third quarter of 2019 included the following:

a. $21.8 million gain on derivative contracts

b. $5.9 million of merger and integration costs associated with the merger with Carrizo

c. $8.3 million loss on redemption of Preferred Stock

(5) Fourth quarter of 2019 included the following:

a. Activity from the Carrizo Acquisition subsequent to the December 20, 2019 closing date.

b. $68.4 million of merger and integration costs associated with the merger with Carrizo

c. $30.7 million loss on derivative contracts

d. $4.9 million loss on extinguishment of debt

(6) Second quarter of 2018 included the following:

a. $16.6 million loss on derivative contracts

(7) Third quarter of 2018 included the following:

a. $34.3 million loss on derivative contracts

(8) Fourth quarter of 2018 included the following:

a. 103.9 million gain on derivative contracts

ITEM 9. Changes In and Disagreements with Accountants on Accounting and Financial Disclosure

None.

ITEM 9A. Controls and Procedures

Disclosure controls and procedures. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in the reports that it files or submits under the Exchange Act is accumulated and communicated to the issuer's management, including its principal executive and financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. Our Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") performed an evaluation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). Based on this evaluation, our principal executive and principal financial officers have concluded that the Company's disclosure controls and procedures were effective as of December 31, 2019.

Management's report on internal control over financial reporting. Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Our internal control structure is designed to provide reasonable assurance to our management and Board of Directors regarding the reliability of financial reporting and the preparation and fair presentation of our financial statements prepared for external purposes in accordance with U.S. generally accepted accounting principles. Under the supervision and with the participation of our management, including our CEO and CFO, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2019 based on the framework in *Internal Control – Integrated Framework* published by the Committee of Sponsoring Organizations (COSO) of the Treadway Commission (2013 framework) (the COSO criteria). Based on that evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2019. Management's evaluation of, and conclusion on, the effectiveness of internal control over financial reporting did not include the internal controls of the entities acquired in the merger with Carrizo on December 20, 2019. Carrizo's total assets and total operating revenue represented approximately 40% of the Company's consolidated total assets at December 31, 2019 and 4% of the Company's consolidated total operating revenue for the year ended December 31, 2019.

Because of its inherent limitations, internal control over financial reporting can provide only reasonable assurance that the objectives of the control system are met and may not prevent or detect misstatements. In addition, any evaluation of the effectiveness of internal controls over financial reporting in future periods is subject to risk that those internal controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Company's independent registered public accounting firm, Grant Thornton, LLP, has issued an attestation report regarding its assessment of the Company's internal control over financial reporting as of December 31, 2019, presented preceding the Company's financial statements included in Part II, Item 8 of this 2019 Annual Report on Form 10-K. Additionally, the financial statements for the years ended December 31, 2018 and 2017, covered in this 2019 Annual Report on Form 10-K, have also been audited by the Company's independent registered public accounting firm, whose report is presented preceding the their report on the Company's internal control over financial reporting, included in Part II, Item 8.

Changes in internal control over financial reporting. As noted under "*Management's report on internal control over financial reporting*", management's evaluation of, and conclusion on, the effectiveness of internal control over financial reporting did not include the internal controls of the entities acquired in the merger with Carrizo on December 20, 2019. Under guidelines established by the SEC, companies are permitted to exclude acquisitions from their assessment of internal control over financial reporting during the first year of an acquisition while integrating the acquired company. The Company is in the process of integrating Carrizo'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 were no changes to our internal control over financial reporting during our last fiscal quarter that have materially affected, or are reasonable likely to materially affect, our internal control over financial reporting.

ITEM 9B. Other Information

None.

PART III.

ITEM 10. Directors, Executive Officers and Corporate Governance

For information concerning Item 10, see the definitive proxy statement of Callon relating to the Annual Meeting of Stockholders to be held on May 14, 2020, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

The Company has adopted a code of ethics that applies to the Company's officers, directors, employees, agents and representatives and includes a code of ethics for senior financial officers that applies to the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer. The full text of such code of ethics has been posted on the Company's website at www.callon.com, and is available free of charge in print to any shareholder who requests it. Request for copies should be addressed to the Secretary at mailing address 2000 W. Sam Houston Parkway South, Suite 2000, Houston, TX 77042.

ITEM 11. Executive Compensation

For information concerning Item 11, see the definitive proxy statement of Callon relating to the Annual Meeting of Stockholders to be held on May 14, 2020, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

ITEM 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

For information concerning the security ownership of certain beneficial owners and management, see the definitive proxy statement of Callon relating to the Annual Meeting of Stockholders to be held on May 14, 2020, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

ITEM 13. Certain Relationships and Related Transactions and Director Independence

For information concerning Item 13, see the definitive proxy statement of Callon relating to the Annual Meeting of Stockholders to be held on May 14, 2020, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

ITEM 14. Principal Accountant Fees and Services

For information concerning Item 14, see the definitive proxy statement of Callon relating to the Annual Meeting of Stockholders to be held on May 14, 2020, which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

PART IV.

ITEM 15. Exhibits

The following is an index to the financial statements and financial statement schedules that are filed in Part II, Item 8 of this report on Form 10-K.

Exhibit Number		Description	Incorporated by reference (File No. 001-14039, unless otherwise indicated)		
			Form	Exhibit	Filing Date
2.1		Purchase and Sale Agreement, dated May 23, 2018, between Cimarex Energy Co, Prize Energy Resources, Inc., and Magnum Hunter Production, Inc. and Callon Petroleum Operating Company	8-K	2.1	05/24/2018
2.2	(d)	Purchase and Sale Agreement between Callon Petroleum Operating Company and Sequitur Permian, LLC dated April 8, 2019	8-K	2.1	06/13/2019
2.3	(d)	Agreement and Plan of Merger, dated as of July 14, 2019, by and between Callon Petroleum Company and Carrizo Oil & Gas, Inc.	8-K	2.1	07/15/2019
2.4		Amendment No. 1 to Agreement and Plan of Merger, dated August 19, 2019, by and between Callon Petroleum Company and Carrizo Oil & Gas, Inc.	10-Q	2.2	11/05/2019
2.5		Amendment No. 2 to Agreement and Plan of Merger, dated November 13, 2019, by and between Callon Petroleum Company and Carrizo Oil & Gas, Inc.	8-K	2.1	11/14/2019
3.1		Certificate of Incorporation of the Company, as amended through May 12, 2016	10-Q	3.1	11/03/2016
3.2		Certificate of Amendment to the Certificate of Incorporation of Callon, effective December 20, 2019	8-K	3.1	12/20/2019
3.3		Amended and Restated Bylaws of the Company	10-K	3.2	02/27/2019
4.1		Specimen Common Stock Certificate	10-K	4.1	02/28/2018
4.2	(a)	Description of Common Stock			
4.3		Indenture of 6.125% Senior Notes Due 2024, dated as of October 3, 2016, among Callon Petroleum Company, the Guarantors party thereto and U.S. Bank National Association, as Trustee	8-K	4.1	10/04/2016
4.4		First Supplemental Indenture, dated December 20, 2019, among Callon, the Guarantors named therein and U.S. Bank National Association, as trustee	8-K	4.3	12/20/2019
4.5		Registration Rights Agreement of 6.125% Senior Notes Due 2024, dated October 3, 2016, among Callon Petroleum Company, Callon Petroleum Operating Company and J.P. Morgan Securities LLC, as representative of the Initial Purchasers named on Annex E thereto	8-K	4.2	10/04/2016
4.6		Registration Rights Agreement of 6.125% Senior Notes Due 2024, dated May 24, 2017, among Callon Petroleum Company, Callon Petroleum Operating Company and J.P. Morgan Securities LLC, as representative of the Initial Purchasers named on Annex E thereto	8-K	4.1	05/24/2017
4.7		Indenture of 6.375% Senior Notes Due 2026, dated as of June 7, 2018, among Callon Petroleum Company, the Guarantors party thereto and U.S. Bank National Association, as Trustee	8-K	4.1	06/07/2018
4.8		First Supplemental Indenture, dated December 20, 2019, among Callon, the Guarantors named therein and U.S. Bank National Association, as trustee	8-K	4.4	12/20/2019
4.9		Registration Rights Agreement of 6.375% Senior Notes Due 2026, dated June 7, 2018, among Callon Petroleum Company, Callon Petroleum Operating Company and J.P. Morgan Securities LLC, as representative of the Initial Purchasers named on Annex E thereto	8-K	4.2	06/07/2018
4.10		Indenture, dated May 28, 2008, among Carrizo Oil & Gas, Inc., the subsidiaries named therein and Wells Fargo Bank, National Association, as trustee	8-K(File No. 000-29187-87)	4.1	05/28/2008
4.11		Sixteenth Supplemental Indenture, dated April 28, 2015, among Carrizo Oil & Gas, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee	8-K(File No. 000-29187-87)	4.2	04/28/2015
4.12		Eighteenth Supplemental Indenture, dated May 20, 2015, among Carrizo Oil & Gas, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee	8-K(File No. 000-29187-87)	4.2	05/22/2015
4.13		Twentieth Supplemental Indenture, dated July 14, 2017, among Carrizo Oil & Gas, Inc., the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee	8-K(File No. 000-29187-87)	4.2	07/14/2017
4.14		Twenty-First Supplemental Indenture, dated December 20, 2019, among Callon, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee	8-K	4.1	12/20/2019
4.15		Twenty-Second Supplemental Indenture, dated December 20, 2019, among Callon, the Guarantors named therein and Wells Fargo Bank, National Association, as trustee	8-K	4.2	12/20/2019
4.16		Warrant Agreement, dated as of December 20, 2019, between Callon and American Stock Transfer And Trust Company, LLC, as warrant agent	8-K	4.5	12/20/2019
10.1	(d)	Credit Agreement, dated December 20, 2019, among Callon, JPMorgan Chase Bank, National Association, as administrative agent, and the lenders party thereto	8-K	10.1	12/20/2019
10.2	(b)	Callon Petroleum Company 2011 Omnibus Incentive Plan	DEF 14A	A	03/21/2011
10.3	(b)	Form of Callon Petroleum Company Restricted Stock Unit Award Agreement, adopted on March 12, 2015	10-K	10.16	03/03/2016
10.4	(b)	First Amendment to the Callon Petroleum Company 2011 Omnibus Incentive Plan	10-Q	10.1	11/05/2015

10.5		Amended and Restated Deferred Compensation Plan for Outside Directors - Callon Petroleum Company, dated as of May 10, 2017 and effective as of May 1, 2017	10-K	10.11	02/28/2018
10.6	(b)	Callon Petroleum Company 2018 Omnibus Incentive Plan	DEF 14A	A	03/23/2018
10.7	(a)	Amended and Restated 2018 Omnibus Incentive Plan			
10.8	(b)	Form of Callon Petroleum Company Director Restricted Stock Unit Award Agreement, adopted on May 10, 2018 under the 2018 Omnibus Incentive Plan	10-Q	10.4	08/07/2018
10.9	(b)	Form of Callon Petroleum Company Employee Restricted Stock Unit Award Agreement, adopted on May 10, 2018 under the 2018 Omnibus Incentive Plan	10-Q	10.5	08/07/2018
10.10	(b)	Form of Callon Petroleum Company Employee Cash-Settleable Performance Share Award Agreement, adopted on May 10, 2018 under the 2018 Omnibus Incentive Plan	10-Q	10.6	08/07/2018
10.11	(b)	Form of Callon Petroleum Company Employee Stock-Settleable Performance Share Award Agreement, adopted on May 10, 2018 under the 2018 Omnibus Incentive Plan	10-Q	10.7	08/07/2018
10.12	(b)	Form of Change in Control Severance Compensation Agreement, dated as of January 1, 2019, by and between Callon Petroleum Company and its executive officers	10-K	10.17	02/27/2019
10.13	(b)	Change in Control Severance Compensation Agreement, dated as of January 1, 2019, by and between Joseph C. Gatto, Jr., and Callon Petroleum Company	10-K	10.18	02/27/2019
10.14	(b)	Carrizo Oil & Gas, Inc. Change in Control Severance Plan effective February 14, 2019	10-K(File No. 000-29187-87)	10.15	03/01/2019
10.15		Separation Agreement, dated January 2, 2019, by and between Gary A. Newberry and Callon Petroleum Company	10-K	10.19	02/27/2019
10.16		Separation Agreement, dated March 13, 2019, by and between Jerry A. Weant and Callon Petroleum Company	10-Q	10.1	05/07/2019
10.17	(b)	Form of Callon Petroleum Company Employee Restricted Stock Unit Award Agreement, adopted on January 31, 2019 under the 2018 Omnibus Incentive Plan	10-K	10.20	02/27/2019
10.18	(b)	Form of Callon Petroleum Officer Cash-Settleable Performance Share Award Agreement, adopted on January 31, 2019 under the 2018 Omnibus Incentive Plan	10-K	10.21	02/27/2019
10.19	(b)	Form of Callon Petroleum Company Officer Stock-Settleable Performance Share Award Agreement, adopted on January 31, 2019 under the 2018 Omnibus Incentive Plan	10-K	10.22	02/27/2019
10.20	(b)	Form of Callon Petroleum Company Officer Restricted Stock Unit Award Agreement, adopted on January 31, 2019 under the 2018 Omnibus Incentive Plan	10-K	10.23	02/27/2019
10.21	(b)	2017 Incentive Plan of Carrizo Oil &Gas, Inc.	8-K(File No. 000-29187-87)	10.1	05/16/2019
10.22	(a)	Form of Callon Petroleum Company Employee Restricted Stock Unit Award Agreement, adopted on January 31, 2020 under the Amended & Restated 2018 Omnibus Incentive Plan			
10.23	(a)	Form of Callon Petroleum Officer Cash-Settleable Performance Share Award Agreement, adopted on January 31, 2020 under the Amended & Restated 2018 Omnibus Incentive Plan			
10.24	(a)	Form of Callon Petroleum Company Officer Stock-Settleable Performance Share Award Agreement, adopted on January 31, 2020 under the Amended & Restated 2018 Omnibus Incentive Plan			
10.25	(a)	Form of Callon Petroleum Company Officer Restricted Stock Unit Award Agreement, adopted on January 31, 2020 under the Amended & Restated 2018 Omnibus Incentive Plan			
21.1	(a)	Subsidiaries of the Company			
23.1	(a)	Consent of Grant Thornton LLP			
23.2	(a)	Consent of DeGolyer and MacNaughton, Inc.			
23.3	(a)	Consent of Ryder Scott Company, L.P.			
31.1	(a)	Certification of Chief Executive Officer pursuant to Rule 13(a)-14(a)			
31.2	(a)	Certification of Chief Financial Officer pursuant to Rule 13(a)-14(a)			
32.1	(c)	Section 1350 Certifications of Chief Executive and Financial Officers pursuant to Rule 13(a)-14(b)			
99.1	(a)	Reserve Report Summary prepared by DeGolyer and MacNaughton, Inc. as of December 31, 2019			
99.2	(a)	Reserve Report Summary prepared by Ryder Scott Company, L.P. as of December 31, 2019			
101.INS	(a)	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.			
101.SCH	(a)	Inline XBRL Taxonomy Extension Schema Document			
101.CAL	(a)	Inline XBRL Taxonomy Extension Calculation Linkbase Document.			
101.DEF	(a)	Inline XBRL Taxonomy Extension Definition Linkbase Document.			
101.LAB	(a)	Inline XBRL Taxonomy Extension Label Linkbase Document.			
101.PRE	(a)	Inline XBRL Taxonomy Extension Presentation Linkbase Document.			
104	(a)	Cover Page Interactive Data File - the cover page interactive data file does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.			

(a) Filed herewith.
(b) Indicates management compensatory plan, contract, or arrangement.
(c) Furnished herewith. Pursuant to SEC Release No. 33-8212, this certification will be treated as “accompanying” this report and not “filed” as part of such report for purposes of Section 18 of the Exchange Act or otherwise subject to the liability of Section 18 of the Exchange Act, and this certification will not be

deemed to be incorporated by reference into any filing under the Securities Act of 1933, except to the extent that the registrant specifically incorporates it by reference.

(d) Certain schedules and similar attachments have been omitted pursuant to Item 601(a)(5) of Regulation S-K. Callon agrees to furnish a supplemental copy of any omitted schedule or attachment to the SEC upon request.

ITEM 16. Form 10-K Summary

Not applicable.

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.

Callon Petroleum Company

/s/ James P. Ulm, II	Date:	February 28, 2020
By: James P. Ulm, II Chief Financial Officer (principal financial 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.

/s/ Joseph C. Gatto, Jr.	Date:	February 28, 2020
Joseph C. Gatto, Jr. (principal executive officer)		
/s/ James P. Ulm, II	Date:	February 28, 2020
James P. Ulm, II (principal financial officer)		
/s/ Gregory F. Conaway	Date:	February 28, 2020
Gregory F. Conaway (principal accounting officer)		
/s/ L. Richard Flury	Date:	February 28, 2020
L. Richard Flury (chairman of the board of directors)		
/s/ Frances Aldrich Sevilla-Sacasa	Date:	February 28, 2020
Frances Aldrich Sevilla-Sacasa (director)		
/s/ Matthew R. Bob	Date:	February 28, 2020
Matthew R. Bob (director)		
/s/ Barbara J. Faulkenberry	Date:	February 28, 2020
Barbara J. Faulkenberry (director)		
/s/ Michael L. Finch	Date:	February 28, 2020
Michael L. Finch (director)		
/s/ S.P. Johnson IV	Date:	February 28, 2020
S.P. Johnson IV (director)		
/s/ Larry D. McVay	Date:	February 28, 2020
Larry D. McVay (director)		
/s/ Anthony J. Nocchiero	Date:	February 28, 2020
Anthony J. Nocchiero (director)		
/s/ James M. Trimble	Date:	February 28, 2020
James M. Trimble (director)		
/s/ Steven A. Webster	Date:	February 28, 2020
Steven A. Webster (director)		

REGULATION G – NON-GAAP FINANCIAL MEASURES

This 2019 Annual Report contains measures which may be deemed "non-GAAP financial measures" as defined in Item 10 of Regulation S-K of the Securities Exchange Act of 1934, as amended.

RECONCILIATION OF NET INCOME (GAAP) TO ADJUSTED EBITDA (NON-GAAP)

We calculate adjusted earnings before interest, income taxes, depreciation, depletion and amortization ("Adjusted EBITDA") as net income (loss) before interest expense, income taxes, depreciation, depletion and amortization, asset retirement obligation accretion expense, (gains) losses on derivative instruments excluding net settlements, impairment of oil and natural gas properties, non-cash equity based compensation, and other operating expenses. Adjusted EBITDA is not a measure of financial performance under GAAP. Accordingly, it should not be considered as a substitute for net income (loss), operating income (loss), cash flow provided by operating activities, or other income or cash flow data prepared in accordance with GAAP. However, we believe that Adjusted EBITDA provides additional information with respect to our performance or ability to meet our future contractual obligations, capital expenditures and working capital requirements. Because Adjusted EBITDA excludes some, but not all, items that affect net income (loss) and may vary among companies, the Adjusted EBITDA presented may not be comparable to similarly titled measures of other companies.

FY 2019[1]	($000s)
Net income	67,928
Loss on derivatives, net	62,109
Cash paid for commodity derivative settlements, net	(3,789)
Non-cash stock-based compensation expense	11,364
Merger-related expenses	74,363
Other operating expense	1,076
Income tax expense	35,301
Interest expense	2,907
Depreciation, depletion and amortization	244,991
Accretion expense	945
Loss on extinguishment of debt	4,881
Adjusted EBITDA	$ 502,076
Adj. EBITDA per BOE	$33.28
Total Production MBOE	15,086

[1] Includes Carrizo results from December 21 to December 31, 2019.

CORPORATE DATA

STOCKHOLDER INFORMATION

Callon Website
The Company website can be found at www.callon.com. It contains news releases, corporate governance materials, the annual report, recent investor presentations, stock quotes, and a link to SEC filings.

Common Stock Dividend Policy
It is anticipated that all available funds will be reinvested in the Company's business activities. Therefore, the Company has no current plans to pay dividends on its common stock.

Market for Common Stock
Effective April 22, 1998, the Company's Common Stock began trading on the New York Stock Exchange under the symbol "CPE."

CEO Section 303A.12(A) Certification
In accordance with requirements mandated by the New York Stock Exchange under Section 303A.12(a) of the Listed Company Manual, each public company is required to disclose in its Annual Report to Shareholders that its CEO certification was filed and to state any qualifications to such certification. On behalf of Joseph C. Gatto, Jr., the company filed the required certification on February 28, 2020 without qualification.

Notice Of Annual Shareholders' Meeting
The Annual Meeting of Shareholders will be held Monday, June 8, 2020, at 9:00 a.m. in the La Scala room of The Moran Hotel, 800 Sorella Ct, Houston, TX 77024. Information with respect to this meeting is contained in the Proxy Statement sent to shareholders of record as of April 29, 2020. The 2019 Annual Report is not to be considered a part of the proxy soliciting materials.

Transfer Agent and Registrar
AST Financial
6201 15th Avenue
Brooklyn, New York 11219
(718) 921-8200

Independent Registered Public Accounting Firm
Grant Thornton LLP
Houston, Texas

Administrative Agent Bank
JPMorgan Chase Bank, N.A.
New York, New York

Headquarters
Callon Headquarters Building
2000 W. Sam Houston Parkway South
Suite 2000
Houston, TX 77042

Mailing Address
Callon Petroleum Company
2000 W. Sam Houston Parkway South
Suite 2000
Houston, TX 77042

Permian Operations Office
Callon Petroleum Company
6 Desta Drive, 4th Floor
Midland, Texas 79705

Eagle Ford Operations Office
Callon Petroleum Company
262 County Line Road
Dilley, Texas 78017

Form 10-K
The Company's Annual Report on Form 10-K, as audited by Grant Thornton, excluding exhibits, has been incorporated into this Annual Report.

OFFICERS OF THE COMPANY

Joseph C. Gatto, Jr.
President and Chief Executive Officer

James P. Ulm, II
Senior Vice President and Chief Financial Officer

Dr. Jeffrey S. Balmer
Senior Vice President and Chief Operating Officer

Michol L. Ecklund
Senior Vice President, General Counsel and Corporate Secretary

Michael J. O'Connor
Vice President, Permian Operations

Liam Kelly
Vice President of Corporate Development

Jamin B. McNeil
Vice President–Production

J. Michael Hastings
Vice President–Marketing

Gregory F. Conaway
Vice President and Chief Accounting Officer

Rex A. Bigler
Vice President–Asset Development

Scott H. Hudson
Vice President of Drilling and Completions

BOARD OF DIRECTORS

Richard L. Flurry, Chairman of the Board
Former Chief Executive,
Gas, Power and Renewables
British Petroleum plc (retired)
Director, McDermott International

Matthew R. Bob
President, Eagle Oil & Gas Company
Director, Southcross Energy

Major General (Ret.) Barbara Faulkenberry
Former Major General,
Vice Commander U.S. Air Force
Director, USA Truck

Michael L. Finch
Former Chief Financial Officer
and Director, Stone Energy
Former Director, Petroquest Energy

S.P. "Chip" Johnson
Former Chief Executive Officer,
Carrizo Oil & Gas

Larry D. McVay
Former Chief Operating Officer
TNK-BP Holdings British Petroleum plc
Joint Venture (retired)
Director, Linde plc

Anthony J. Nocchiero
Former Sr. Vice President
and Chief Financial Officer
CF Industries, Inc. (retired)

Frances Aldrich Sevilla-Secasa
Former Chief Executive Officer,
Banco Itau International
Former Director, Carrizo Oil & Gas, Inc.
Director, Camden Property Trust

James M. Trimble
Former Interim Chief Executive Officer
and President, and Director, Stone Energy
Corporation Director, Talos Energy, LLC

Steven A. Webster
Managing Partner, AEC Partners,
formerly Avista Capital
Former Director and Chairman,
Carrizo Oil & Gas, Inc.
Director, Camden Property Trust
Director, Era Group, Inc.
Director, Oceaneering International, Inc.

Joseph C. Gatto, Jr.
President and Chief Executive Officer

2019 Annual Report
This Annual Report and the statements contained in it are submitted for the general information of the shareholders of Callon Petroleum Company. The information is not presented in connection with the sale or the solicitation of any offer to buy any securities, nor is it intended to be a representation by the Company of the value of its securities. If you have questions regarding this Annual Report or the Company, or would like additional copies of this report, please contact our Investor Relations Department at 2000 W. Sam Houston Parkway South, Suite 2000, Houston, TX 77042. Phone: (281) 589-5200, Email: ir@callon.com

Investors, Security Analysts And Media Relations
Shareholders, brokers, securities analysts, portfolio managers, or financial news media seeking information about the company may email us at ir@callon.com or call Mark Brewer, Investor Relations @ 281-589-5200. Written inquiries may be sent to 2000 W. Sam Houston Parkway South, Suite 2000, Houston, TX 77042.

CALLON.COM
NYSE: CPE