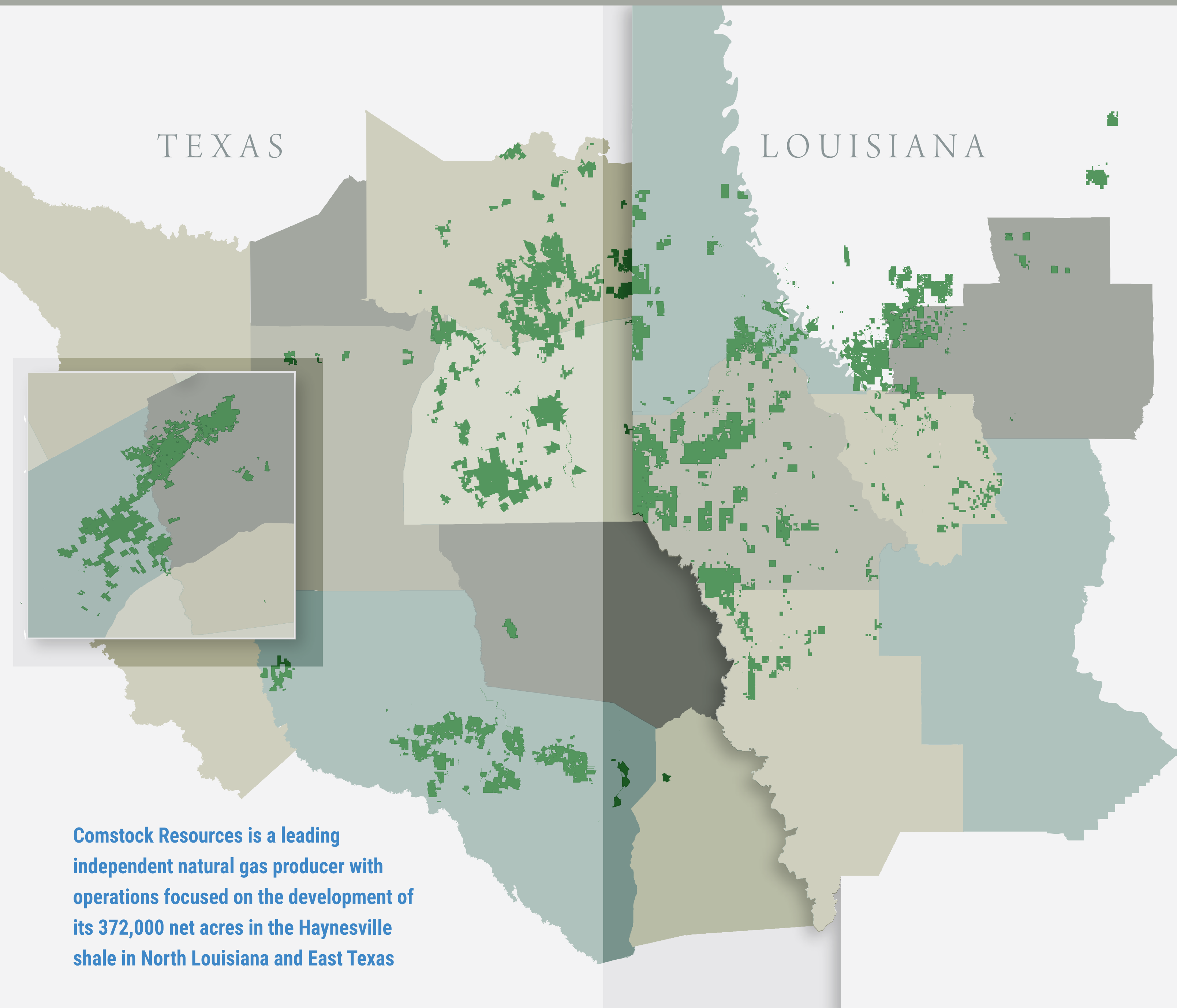
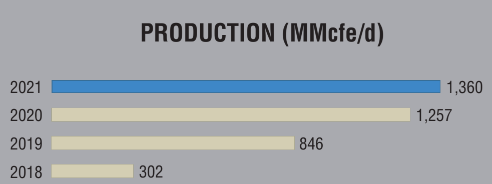
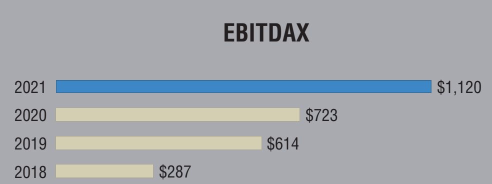
COMSTOCK RESOURCES

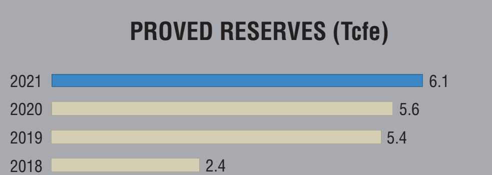
2021 ANNUAL REPORT

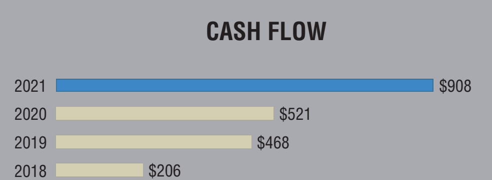


Comstock Resources is a leading independent natural gas producer with operations focused on the development of its 372,000 net acres in the Haynesville shale in North Louisiana and East Texas









To our stockholders:

2021 was a turnaround year for the Company. We exceeded the goals we put in place for the year including generating in excess of $200 million in free cash flow and reducing leverage to below 2.5x. We also reduced our cost of capital by refinancing our high coupon bonds. We added approximately 49,000 net acres to our Haynesville footprint to continue to build up our already substantial drilling prospect inventory.

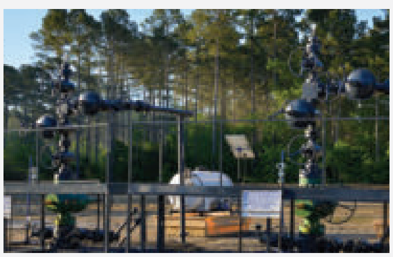
Solid Results from Our 2021 Drilling Program

We had another strong year with the drill bit. We have drilled and completed 331 horizontal Haynesville/Bossier wells since 2015, more than any other operator in the play. Those wells had an average IP rate of 23 MMcf per day. Under our 2021 Haynesville/Bossier shale drilling program, we drilled 64 (51.9 net) successful operated wells which had an average per well initial production rate of 23 MMcf per day.

In 2021, we improved our drilling performance by 25% by drilling on average just over 1,000 feet per day as compared to 800 feet per day in 2020. We set a new corporate record with our fastest well to date which averaged 1,461 feet drilled per day. In 2021, the average lateral length for all the wells we drilled increased to 8,800 feet, including our record longest lateral to date of 15,155 feet. This is one of four 15,000 foot laterals we drilled in 2021. Building on the success of these ultra long laterals, we expect the average lateral length of our wells to be drilled in 2022 to average over 10,000 feet. In 2022, we anticipate drilling approximately 21 wells with laterals longer than 11,000 feet, with nine of these being 15,000 foot laterals. This will increase our average lateral length for wells drilled in 2022 by almost 20%. By continuing to execute our long lateral strategy, we will be able to better maintain our low cost structure in the anticipated higher service cost environment.

Grew Proved Reserve Base at Low Finding Cost of 60¢ per Mcfe

In 2021, we were able to grow proved reserves by 9% to 6.1 trillion cubic feet of natural gas equivalent. The growth in proved reserves replaced 199% of our 2021 production and was achieved at a low finding cost of 60¢ per Mcfe. The present value discounted at 10% of our proved reserves was $6.8 billion.



Improving our Balance Sheet and Lowering our Cost of Capital

As the outlook for natural gas prices continued to improve in 2021, we were able to refinance $2 billion of our senior notes in March and June, saving $48 million in cash interest payments per year with the lower coupons on the new bonds. The refinancing transactions also extended our senior notes weighted average maturity by almost three years.

We repaid $265 million outstanding under our bank facility in 2021, increasing our financial liquidity to $1.2 billion. Our leverage ratio improved to 2.2x in the fourth quarter of 2021, down from 3.8x in 2020.

Strong Financial Results

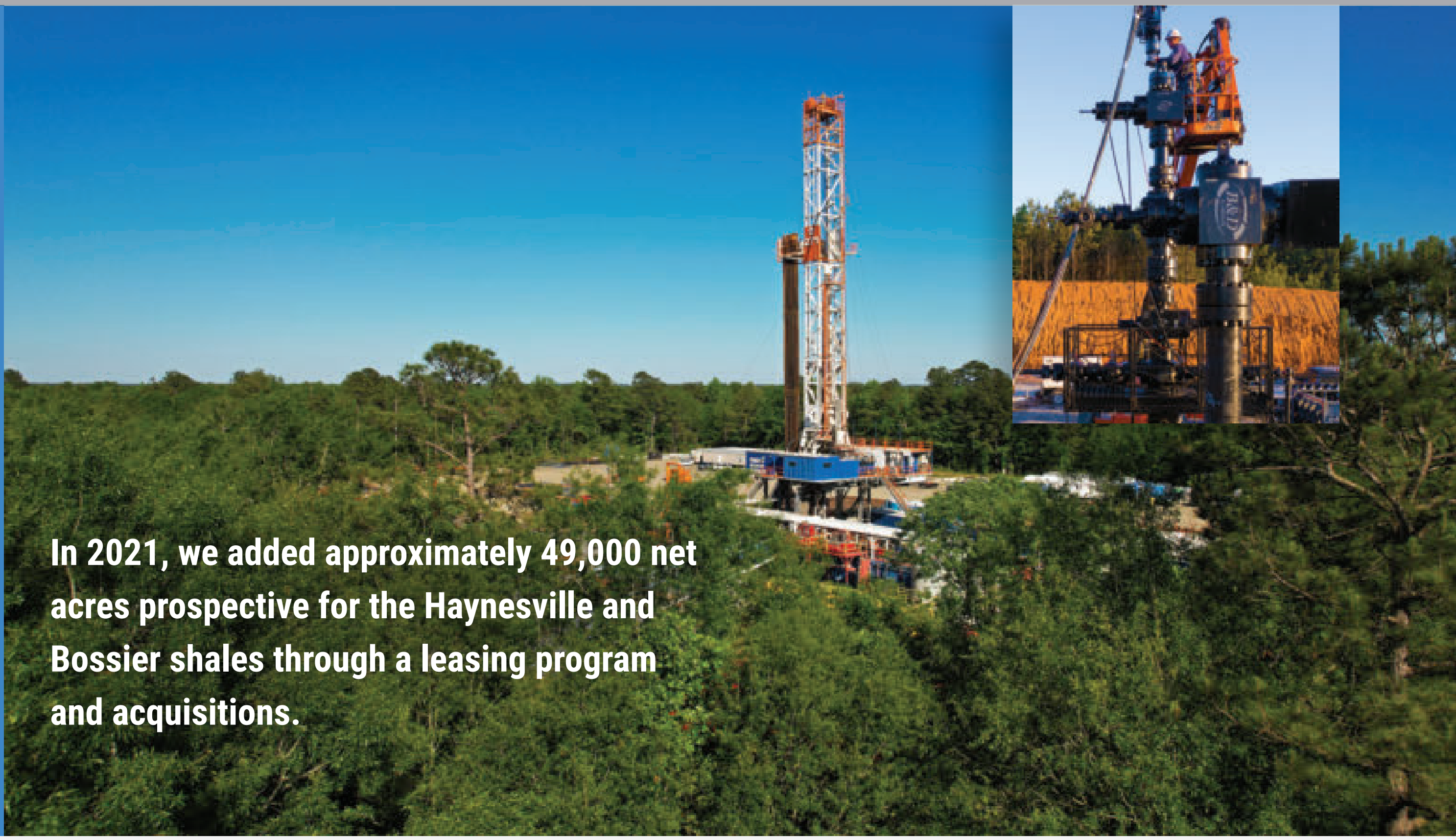
Our adjusted net income available to common stockholders increased in 2021 over 500% from 2020 to $303 million or $1.16 per diluted share. Net income was adjusted to exclude certain items not related to normal operating activities, which in 2021 was primarily losses from the early

retirement of debt, the sale of our Bakken shale properties and the unrealized loss related to our contracts to hedge future natural gas prices.

We produced 489 Bcf of natural gas and 1.2 million barrels of oil in 2021. Our natural gas production averaged 1.3 Bcf per day in 2021, an increase of 9% over natural gas production in 2020. The higher gas production combined with stronger oil and natural gas prices drove 44% growth in our oil and gas sales, after hedging, to $1.4 billion. We generated Adjusted EBITDAX of $1.1 billion, which increased 55% over 2020. Our operating cash flow in 2021 of $908 million grew 74% over 2020. Our EBITDAX margin in 2021 was 78%, one of the highest in the industry. We also achieved a 12% return on average capital employed and a 27% return on average equity.

Substantial Free Cash Flow Generation

We generated free cash flow from operations of $262 million in 2021, representing a free cash flow yield of 29%. Including the acquisition and divestitures we completed in 2021, we generated a total of $343 million in



free cash flow. We used the free cash flow toward debt reduction. Our goal is to reduce our financial leverage to under 1.5 times before reinstating our dividend and initiating a return of capital program. We expect to reach this goal in 2022.

Industry Leading Low Operating Cost Structure

We continue to have one of the industry's lowest operating cost structures. Our total operating costs per Mcfe produced averaged 63¢ in 2021. Our gathering and transportation costs averaged 26¢ per Mcfe in 2021, which is substantially lower than any other significant natural gas producer. Our general and administrative costs averaged only 6¢ per Mcfe in 2021 and our other operating costs per Mcfe, including production taxes, averaged 31¢ per Mcfe in 2021.

Value Added Acquisitions

In 2021, we added approximately 49,000 net acres prospective for the Haynesville and Bossier shales through a leasing program and acquisitions. Included in that activity was an attractive $35 million bolt-on acquisition in East Texas. The acquisition included 18.1 net producing wells and 17,331 net acres. With the acquisition, we added 57.9 net drilling locations, which represents approximately one year's worth of our drilling activity.

Environmental Stewardship

We are committed to environmental stewardship and a responsible energy future. We already have a low GHG emissions profile and we have several initiatives ongoing to continue to improve, including using cleaner burning natural gas rather than diesel fuel to reduce emissions in our drilling and completion operations. In 2022, we expect to employ BJ Energy Solutions' next generation fracturing fleet, which is fueled by 100% natural gas, in our Haynesville shale development program.

Our most significant environmental

initiative is our partnership with MiQ to initiate the certification of our natural gas production in the Haynesville shale under the MiQ methane standard. MiQ will oversee an independent, third-party audited assessment of methane emissions from our Haynesville shale gas production. The certification will cover 2 Bcf of natural gas that we produce for ourselves and our partners. This initiative demonstrates our commitment to produce our natural gas under strict environmental standards and will allow us to deliver differentiated, responsibly sourced natural gas to our customers. We anticipate that we can achieve this certification during the first half of 2022.

Outlook for 2022

2022 is expected to be an outstanding year for natural gas and the Company. We expect to be able to

meet our debt reduction goal and reinstate a dividend to our stockholders later in the year. We expect our 2022 drilling program to generate 4% to 5% production growth and we expect to generate in excess of $500 million of free cash flow based on the current natural gas price outlook.

In 2022, the lateral length of our planned wells is expected to be 19% longer than our 2021 wells. The additional investment we are making this year in our drilling program is expected to pay off in future years as the longer lateral wells have a lower decline rate than the shorter laterals.

In 2022, our operating plan is focused on repaying $479 million of debt, including redeeming our 2025 senior notes. We continue to have an industry leading low cost structure, which gives us best in class drilling returns. At the end of 2021, we had financial liquidity of almost $1.2 billion, which is expected to increase further in 2022 as we repay the remaining borrowings outstanding on our bank credit facility.

The directors and management of Comstock want to thank the stockholders for their continued support.

M. Jay Allison
Chairman and Chief Executive Officer

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2021

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 No. 001-03262

COMSTOCK RESOURCES, INC.

(Exact name of registrant as specified in its charter)

Nevada	**94-1667468**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification Number)*

5300 Town and Country Blvd., Suite 500, Frisco, Texas 75034

(Address of principal executive offices including zip code)

972 668-8800

(Registrant's telephone number and area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	*Trading Symbol(s)*	*Name of each exchange on which registered*
Common Stock, par value $0.50 (per share)	**CRK**	**New York Stock Exchange**

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 registrant has elected to not use the extended transition period for complying with any new or revised final accounting standards provided pursuant to Section 13(a) of the Exchange Act. Emerging growth company ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☑

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

The aggregate market value of the common stock held by non-affiliates of the registrant, based on the closing price of common stock on the New York Stock Exchange on June 30, 2021 (the last business day of the registrant's most recently completed second fiscal quarter), was $612.6 million. As of February 16, 2022 there were 232,922,620 shares of common stock of the registrant outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Definitive Proxy Statement for the 2022 Annual Meeting of Stockholders are incorporated by reference into Part III of this report.

COMSTOCK RESOURCES, INC.
ANNUAL REPORT ON FORM 10-K
For the Fiscal Year Ended December 31, 2021

CONTENTS

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

The information contained in this report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These forward-looking statements are identified by their use of terms such as "expect," "estimate," "anticipate," "project," "plan," "intend," "believe" and similar terms. All statements, other than statements of historical facts, included in this report, are forward-looking statements, including statements mentioned under "Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations," regarding:

- amount and timing of future production of oil and natural gas;
- amount, nature and timing of capital expenditures;
- the number of anticipated wells to be drilled after the date hereof;
- the availability of exploration and development opportunities;
- our financial or operating results;
- our cash flow and anticipated liquidity;
- operating costs including lease operating expenses, administrative costs and other expenses;
- finding and development costs;
- our business strategy; and
- other plans and objectives for future operations.

Any or all of our forward-looking statements in this report may turn out to be incorrect. They can be affected by a number of factors, including, among others:

- the risks described in "Risk Factors" and elsewhere in this report;
- the volatility of prices and supply of, and demand for, oil and natural gas;
- the timing and success of our drilling activities;
- the numerous uncertainties inherent in estimating quantities of oil and natural gas reserves and actual future production rates and associated costs;
- our ability to successfully identify, execute or effectively integrate future acquisitions;
- the usual hazards associated with the oil and natural gas industry, including fires, well blowouts, pipe failure, spills, explosions and other unforeseen hazards;
- our ability to effectively market our oil and natural gas;
- the availability of rigs, equipment, supplies and personnel;
- our ability to discover or acquire additional reserves;
- our ability to satisfy future capital requirements;
- changes in regulatory requirements;
- general economic conditions, status of the financial markets and competitive conditions; and
- our ability to retain key members of our senior management and key employees.

DEFINITIONS

The following are abbreviations and definitions of terms commonly used in the oil and gas industry and this report. Natural gas equivalents and crude oil equivalents are determined using the ratio of six Mcf to one barrel. All references to "us", "our", "we" or "Comstock" mean the registrant, Comstock Resources, Inc. and where applicable, its consolidated subsidiaries.

"Bbl" means a barrel of U.S. 42 gallons of oil.

"Bcf" means one billion cubic feet of natural gas.

"Bcfe" means one billion cubic feet of natural gas equivalent.

"BOE" means one barrel of oil equivalent.

"Btu" means British thermal unit, which is the quantity of heat required to raise the temperature of one pound of water from 58.5 to 59.5 degrees Fahrenheit.

"Completion" means the installation of permanent equipment for the production of oil or gas.

"Condensate" means a hydrocarbon mixture that becomes liquid and separates from natural gas when the gas is produced and is similar to crude oil.

"Development well" means a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

"Dry hole" means a well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"Exploratory well" means a well drilled to find a new field or to find a new productive reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

"Gross" when used with respect to acres or wells, production or reserves refers to the total acres or wells in which we or another specified person has a working interest.

"LNG" refers to liquefied natural gas, which is a composition of methane and some mixture of ethane that has been cooled to liquid form for ease and safety of non-pressurized storage or transport.

"MBbls" means one thousand barrels of oil.

"MBbls/d" means one thousand barrels of oil per day.

"Mcf" means one thousand cubic feet of natural gas.

"Mcfe" means one thousand cubic feet of natural gas equivalent.

"MMBbls" means one million barrels of oil.

"MMBOE" means one million barrels of oil equivalent.

"MMBtu" means one million British thermal units.

"MMcf" means one million cubic feet of natural gas.

"MMcf/d" means one million cubic feet of natural gas per day.

"MMcfe/d" means one million cubic feet of natural gas equivalent per day.

"MMcfe" means one million cubic feet of natural gas equivalent.

"Net" when used with respect to acres or wells, refers to gross acres of wells multiplied, in each case, by the percentage working interest owned by us.

"Net production" means production we own less royalties and production due others.

"NGL" refers to natural gas liquids, which is composed exclusively of carbon and hydrogen.

"Oil" means crude oil or condensate.

"Operator" means the individual or company responsible for the exploration, development, and production of an oil or gas well or lease.

"Proved developed reserves" means reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

"Proved developed non-producing" means reserves (i) expected to be recovered from zones capable of producing but which are shut-in because no market outlet exists at the present time or whose date of connection to a pipeline is uncertain or (ii) currently behind the pipe in existing wells, which are considered proved by virtue of successful testing or production of offsetting wells.

"Proved developed producing" means reserves expected to be recovered from currently producing zones under continuation of present operating methods. This category includes recently completed shut-in gas wells scheduled for connection to a pipeline in the near future.

"Proved reserves" means the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided by contractual arrangements.

"Proved undeveloped reserves" means 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 are limited to those drilling locations offsetting productive wells that are reasonably certain of production when drilled or where it can be demonstrated with certainty that there is continuity of production from the existing productive formation.

"PV 10 Value" means the present value of estimated future revenues to be generated from the production of proved reserves calculated, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service, future income tax expense and depreciation, depletion and amortization, and discounted using an annual discount rate of 10%. This amount is the same as the standardized measure of discounted future net cash flows related to proved oil and natural gas reserves except that it is determined without deducting future income taxes. Although PV 10 Value is not a financial measure calculated in accordance with GAAP, management believes that the presentation of PV 10 Value is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account corporate future income taxes and our current tax structure. We use this measure when assessing the potential return on investment related to our oil and gas properties. Because many factors that are unique to any given company affect the amount of estimated future income taxes, we believe the use of a pre-tax measure is helpful to investors when comparing companies in our industry.

"Recompletion" means the completion for production of an existing well bore in another formation from which the well has been previously completed.

"Reserve life" means the calculation derived by dividing year-end reserves by total production in that year.

"Royalty" means an interest in an oil and gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

"3-D seismic" means an advanced technology method of detecting accumulations of hydrocarbons identified by the collection and measurement of the intensity and timing of sound waves transmitted into the earth as they reflect back to the surface.

"SEC" means the United States Securities and Exchange Commission.

"Tcf" means one trillion cubic feet of natural gas.

"Tcfe" means one trillion cubic feet of natural gas equivalent.

"Working interest" means an interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations. The share of production to which a working interest owner is entitled will always be smaller than the share of costs that the working interest owner is required to bear, with the balance of the production accruing to the owners of royalties. For example, the owner of a 100% working interest in a lease burdened only by a landowner's royalty of 12.5% would be required to pay 100% of the costs of a well but would be entitled to retain 87.5% of the production.

"Workover" means operations on a producing well to restore or increase production.

PART I

ITEMS 1 and 2. *BUSINESS AND PROPERTIES*

We are a leading independent natural gas producer operating primarily in the Haynesville shale, a premier natural gas basin located in North Louisiana and East Texas with superior economics given its geographical proximity to the Gulf Coast markets. As of December 31, 2021, 96% of our proved reserves were in the Haynesville and Bossier shale play. We are focused on creating value through the development of our substantial inventory of highly economic and low-risk drilling opportunities in the Haynesville and Bossier shales. Our common stock is listed and traded on the New York Stock Exchange under the symbol "CRK".

Our oil and gas operations are primarily concentrated in Louisiana and Texas. Our oil and natural gas properties are estimated to have proved reserves of 6.1 Tcfe with a PV 10 Value of $6.8 billion as of December 31, 2021. Our proved reserves are principally natural gas, which are 37% developed as of December 31, 2021, with an average reserve life of approximately 12 years.

Strengths

High Quality Properties. As of December 31, 2021, we had 498,962 acres (371,998 net) in the Haynesville and Bossier shale plays, located in North Louisiana and East Texas. Approximately 85% of our Haynesville/Bossier shale net acreage is held-by-production and our Haynesville/Bossier shale properties have extensive development and exploration potential. Advances in drilling and completion technology have allowed us to increase the reserves recovered through longer horizontal lateral length and substantially larger well stimulation. As a result of the improved economic returns, we have focused our development activities primarily on drilling Haynesville and Bossier horizontal wells since 2015.

Our Haynesville and Bossier shale positions are located in one of the premier North American natural gas shale plays and have access to the Gulf Coast market demand related to LNG exports and the petrochemical industry due to its geographic proximity. We believe we are well positioned for future growth due to the following:

- *De-risked, contiguous and prolific oil and natural gas resources*. The Haynesville and Bossier shale plays have been substantially delineated since 2008. We believe that these shale plays represent some of the most consistent and economic natural gas development drilling opportunities in North America.
- *Management and operating team with extensive experience in developing the Haynesville and Bossier shale plays*. We were among the first exploration and production companies to effectively apply horizontal drilling techniques in the Haynesville and Bossier shales beginning in 2007. In 2015, we restarted a drilling program in the Haynesville and Bossier shales utilizing enhanced completion well designs that have significantly improved the economics of these wells. When combining our historical activity with Covey Park Energy LLC ("Covey Park"), which we acquired in 2019, we have drilled and completed 331 (265.4 net) operated wells from 2015 through 2021.
- *Attractive economic returns*. The Haynesville and Bossier shales offer highly economic and low-risk drilling opportunities through application of advanced drilling and completion technologies, including the use of longer laterals, and high intensity fracture stimulation using tighter frac stages and higher proppant loading. Our management and operating team has been instrumental in developing and optimizing some of the most effective completion techniques in the Haynesville and Bossier shales and such completion techniques have resulted in a substantial improvement in initial production rates and recoverable reserves, which has resulted in some of the highest single well rates of return when compared to results from other natural gas basins in North America.
- *Proximity to premium natural gas markets*. Our natural gas production benefits from the strong regional Gulf Coast demand growth driven by a substantial increase in LNG exports, exports to Mexico and new or expanded petrochemical facilities. Producers, such as us, with access to the Gulf Coast natural gas markets are receiving higher net realized prices than most producers in other regions. We are also able to realize higher margins due to our ability to access the extensive midstream infrastructure at attractive rates and lack of above-market midstream commitments.

Value-Added Acquisitions. We closed the acquisition of Covey Park in July 2019 for $2.2 billion. The acquisition included approximately 249,000 net acres and 2.9 Tcfe of proved reserves, and added over 710 MMcfe per day of production and approximately 1,200 future drilling locations. In November 2019, we acquired a private company for $42.3 million in an all-stock transaction, which included approximately 3,155 net acres, 75 (20.1 net) producing wells and 44 (12.7 net) Haynesville/Bossier shale future drilling locations. In 2020 and 2021, we acquired approximately 68,500 net acres prospective for the Haynesville and Bossier shales through acquisitions and an active leasing program.

Successful Drilling Program. We spent $628.2 million on exploration and development activities in 2021, almost exclusively in the Haynesville and Bossier shale. We spent $576.1 million on drilling and completing horizontal Haynesville and Bossier shale wells and an additional $52.1 million on our other properties and other development costs. We drilled 100 (54.1 net) horizontal Haynesville and Bossier wells in 2021, which had an average lateral length of approximately 9,000 feet. Our drilling program in 2021 replaced 161% of our 2021 production.

Efficient Operator. We operated 98% of our proved reserve base as of December 31, 2021. As the operator, we are better able to control operating costs, the timing and plans for future development, the level of drilling and lifting costs, and the marketing of production. As an operator, we receive reimbursements for overhead from other working interest owners, which reduces our general and administrative expenses.

Business Strategy

Our strategy consists of the following principal elements:

- *Prudently grow free cash flow, production and reserves through development of our high-quality inventory of drilling locations*. We have an extensive inventory of de-risked, high-return drilling locations prospective for the Haynesville and Bossier shales. As of December 31, 2021, we have identified 3,409 drilling locations (1,633 net to us) which gives us several years of drilling activity. The average lateral length of our drilling location inventory is 8,520 feet, which is 25% longer than the average lateral length of our inventory at December 31, 2020. The increase is attributable to re-mapping our acreage to include 15,000 foot lateral locations and due to acreage trades with offset operators. We successfully drilled four wells with laterals of approximately 15,000 feet in 2021. Most of these locations are on acreage that is held by production, giving us the ability to allocate capital among projects in a manner that optimizes both costs and returns, resulting in a highly efficient drilling program. We intend to manage the selection of drilling locations and the timing of development and associated capital expenditures to support our conservative operating plan to generate modest growth and free cash flow to support deleveraging our balance sheet and reinstating a return of capital program.

- *Enhance returns on capital through a focus on optimizing full-cycle economics.* We focus on enhancing our return on capital deployed by focusing on optimizing our already industry leading low operating cost structure and by continuing to reduce our drilling and completion costs. We continually monitor and adjust our drilling and completion and operating procedures on a regular basis with the objective of achieving the most economical returns on our portfolio of drilling opportunities. We believe that we will achieve this objective by (i) minimizing our costs to drill and complete wells, (ii) maximizing well production and recoveries by optimizing lateral length, the number of frac stages, perforation intervals and the type of fracture stimulation employed, (iii) producing near pipeline-quality natural gas, which leads to lower processing costs, and (iv) minimizing operating costs through efficient well management.

- *Manage commodity price exposure.* We maintain an active oil and natural gas price hedging program designed to mitigate volatility in oil and natural gas prices and to protect a portion of our expected future cash flows to insure that we have adequate cash flow to meet our financial obligations.

- *Evaluate and pursue strategic acquisition opportunities to grow our reserves, production, and acreage position.* We intend to leverage our management and operating team's significant technical expertise and experience in the Haynesville shale to continue to pursue acquisition opportunities in our region and to successfully execute and integrate acquisitions that will add to our drilling inventory. We plan to continue to pursue strategic acquisitions that complement our high quality asset base and acquire complimentary acreage with an active leasing program.

- *Maintain disciplined financial strategy.* We intend to maintain a conservative operating plan in 2022 with the primary goal of continuing to improve our balance sheet. We are targeting reducing our leverage ratio to less than 1.5 times in 2022. We believe our low operating cost structure combined with maximizing the capital efficiency of our drilling program and maintaining financial discipline will allow us to achieve this goal.

- *Focus on environmental stewardship.* We have entered into a partnership with MiQ to oversee an independent third-party audited assessment of methane emissions from our Haynesville shale natural gas operations. The results may allow us to document to both domestic and international customers that we provide responsibly sourced natural gas. We utilize cleaner burning natural gas rather than diesel fuel when possible to reduce emissions in our drilling and completion operations and design our wells to drill longer laterals and utilize multi-well pad locations to minimize our above-ground footprint.

Property Dispositions

In 2021, the Company sold its non-operated properties in the Bakken shale for $138.1 million after selling expenses. The Bakken shale properties sold included non-operated interests in 442 producing wells (68.3 net) producing approximately 4,500 barrels of oil equivalent per day.

Oil and Natural Gas Reserves

The following table sets forth our estimated proved oil and natural gas reserves as of December 31, 2021:

	Oil (MBbls)	Natural Gas (MMcf)(1)	Total (MMcfe)(1)	PV 10 Value (000's)(2)
Proved Developed:				
Producing	572	2,181,047	2,184,474	$ 3,043,312
Non-producing	55	64,613	64,947	49,870
Total Proved Developed	627	2,245,660	2,249,421	3,093,182
Proved Undeveloped	—	3,872,423	3,872,423	3,706,914
Total Proved	627	6,118,083	6,121,844	6,800,096
Discounted Future Income Taxes				(1,024,491)
Standardized Measure of Discounted Cash Flows				$ 5,775,605

(1) Natural gas volumes include NGLs. Oil and NGLs are converted to natural gas equivalents by using a conversion factor of one barrel of oil or NGLs for six Mcf of natural gas based upon the approximate relative energy content of oil to natural gas, which is not indicative of oil and natural gas prices.

(2) The PV 10 Value represents the discounted future net cash flows attributable to our proved oil and gas reserves before income tax, discounted at 10%. Although it is a non-GAAP measure, we believe that the presentation of PV 10 Value is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account corporate future income taxes and our current tax structure. We use this measure when assessing the potential return on investment related to our oil and gas properties. The standardized measure of discounted future net cash flows represents the present value of future cash flows attributable to our proved oil and gas reserves after income tax, discounted at 10%.

The following table sets forth our year end reserves as of December 31 for each of the last three fiscal years:

	2021		2020		2019	
	Oil (MBbls)	Natural Gas (MMcf) (1)	Oil (MBbls)	Natural Gas (MMcf) (1)	Oil (MBbls)	Natural Gas (MMcf) (1)
Proved Developed	627	2,245,660	11,000	1,967,288	15,104	1,890,357
Proved Undeveloped	—	3,872,423	—	3,595,588	1,643	3,451,140
Total Proved Reserves	627	6,118,083	11,000	5,562,876	16,747	5,341,497

(1) Natural gas volumes include NGLs. NGLs are converted to natural gas equivalents by using a conversion factor of one barrel of NGLs for six Mcf of natural gas based upon the approximate relative energy content.

96% of our proved reserves are in the Haynesville and Bossier shales in North Louisiana and East Texas. These wells produce from depths of 10,500 to 14,000 feet. All of our proved undeveloped reserves represent wells to be drilled in the next five years on our Haynesville and Bossier shale acreage.

Proved reserves that are attributable to existing producing wells are primarily determined using decline curve analysis and rate transient analysis, which incorporates the principles of hydrocarbon flow. Proved reserves attributable to producing wells with limited production history and for undeveloped locations are estimated using performance from analogous wells in the surrounding area and geologic data to assess the reservoir continuity. Technologies relied on to establish reasonable certainty of economic producibility include electrical logs, radioactivity logs, core analyses, geologic maps and available production data, seismic data and well test data.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

Prices used in determining quantities of oil and natural gas reserves and future cash inflows from oil and natural gas reserves represent the average first of the month prices received at the point of sale for the last twelve months. These prices have been adjusted from index prices for both location and quality differences.

The oil and natural gas prices used for reserves estimation were as follows:

Year	Oil Price (per Bbl)	Natural Gas Price (per Mcf)
2021	$62.38	$3.33
2020	$32.88	$1.71
2019	$50.94	$2.29

Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered, and they are scheduled to be drilled within five years of their initial inclusion as proved reserves, unless specific circumstances justify a longer time. In connection with estimating proved undeveloped reserves for our reserve report, reserves on undrilled acreage were limited to those that are reasonably certain of production when drilled where we can verify the continuity of the reservoir. We only include wells in our proved undeveloped reserves that we currently plan to drill and in which we have adequate capital resources to enable us to drill them. Using empirical evidence, we utilize control points and sample sizes to show continuity in the reservoir. We reflect changes to undeveloped reserves that occur in the same field as revisions to the extent that proved undeveloped locations are revised due to changes in future development plans, including changes to proposed lateral lengths, development spacing and timing of development. As of December 31, 2021, our proved undeveloped reserves did not include any undrilled wells with a rate of return less than 10%.

As of December 31, 2021, our proved undeveloped reserves were comprised of 3.9 Tcf of natural gas consisting of 378 undeveloped locations. All of our natural gas undeveloped reserves are associated with our Haynesville and Bossier shale properties where our 2021 drilling program was focused. Our natural gas proved undeveloped reserves increased by 277 Bcf during 2021. Sixty proved undeveloped locations included in our 2020 reserves were converted to proved developed reserves in 2021.

As of December 31, 2020, our proved undeveloped reserves were comprised of 3.6 Tcf of natural gas, all of which were associated with our Haynesville and Bossier shale properties where our 2020 drilling program was focused. Our natural gas proved undeveloped reserves increased by 144.4 Bcf during 2020. During 2020, 50 proved undeveloped locations were converted to proved developed reserves. Our 2019 proved undeveloped oil reserves were removed from proved reserves in 2020 due to the low oil price that was used to determine proved reserves at December 31, 2020.

The following table presents the changes in our estimated proved undeveloped oil and natural gas reserves for the years ended December 31, 2021, 2020 and 2019:

	Proved Undeveloped Reserves					
	2021		2020		2019	
	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Beginning Balance	—	3,595,588	1,643	3,451,140	2,146	1,699,651
Divestitures	—	(10,592)	—	—	—	(25,179)
Acquisitions	—	196,623	—	—	—	1,853,820
Extension and Discoveries	—	725,120	—	213,658	—	—
Conversion from Undeveloped to Developed	—	(668,427)	(50)	(343,735)	(247)	(188,894)
Revisions	—	34,111	(1,593)	274,525	(256)	111,742
Total Change	—	276,835	(1,643)	144,448	(503)	1,751,489
Ending Balance	—	3,872,423	—	3,595,588	1,643	3,451,140

The timing, by year, when our proved undeveloped reserve quantities are estimated to be converted to proved developed reserves is as follows:

	Proved Undeveloped Reserves					
	2021		2020		2019	
Year ended December 31,	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas MMcf)	Oil (MBbls)	Natural Gas (MMcf)
2020	—	—	—	—	58	363,900
2021	—	—	—	724,329	1,327	578,067
2022	—	636,183	—	639,934	122	795,598
2023	—	782,785	—	705,390	136	956,162
2024	—	852,342	—	721,268	—	757,413
2025	—	812,056	—	804,667	—	—
2026	—	789,057	—	—	—	—
Total	—	3,872,423	—	3,595,588	1,643	3,451,140

The following table presents the timing of our estimated future development capital costs to be incurred for the years ended December 31, 2021, 2020 and 2019:

	Future Development Costs Total Proved Undeveloped Reserves		
	2021	2020	2019
Year ended December 31,		*(in millions)*	
2020	$ —	$ —	$ 286.9
2021	—	445.6	566.6
2022	381.4	438.0	758.6
2023	540.9	519.2	918.7
2024	600.5	499.6	640.6
2025	594.3	549.9	—
2026	576.2	—	—
Total	$ 2,693.3	$ 2,452.3	$ 3,171.4

The following table presents the changes in our estimated future development costs for the years ended December 31, 2021 and December 31, 2020:

	(in millions)
Total as of December 31, 2019	$3,171.4
Development Costs Incurred	(302.1)
Additions and Revisions	(417.0)
Total Changes	(719.1)
Total as of December 31, 2020	2,452.3
Development Costs Incurred	(502.7)
Divestitures	(9.8)
Acquisitions	131.6
Additions and Revisions	621.9
Total Changes	241.0
Total as of December 31, 2021	$2,693.3

Our estimated future capital costs to develop proved undeveloped reserves as of December 31, 2021 of $2.7 billion increased by $0.2 billion from our estimated future capital costs of $2.5 billion as of December 31, 2020.

Our estimated future capital costs to develop proved undeveloped reserves as of December 31, 2020 of $2.5 billion decreased by $0.7 billion from our estimated future capital costs of $3.2 billion as of December 31, 2019. This decrease was primarily attributable to lower expected development costs related to the proved undeveloped Haynesville and Bossier shale locations.

Proved reserve information in this report is based on estimates prepared by our petroleum engineering staff and is the responsibility of management. We retained an independent petroleum consultant to conduct an audit of our December 31, 2021 reserve estimates. Netherland, Sewell & Associates, Inc. ("NSAI") audited PV 10 Values of $6.8 billion, which represented, in the aggregate, 100% of our total PV 10 Value as of December 31, 2021. The purpose of this audit was to provide additional assurance on the reasonableness of internally prepared reserve estimates. This engineering firm was selected for its geographic expertise and historical experience.

The audit letter prepared by our independent petroleum consultant is included as an exhibit to this report. The technical person at the independent petroleum consulting firm responsible for reviewing the reserve estimates presented herein meets the requirements regarding qualifications, independence, objectivity and confidentiality as set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

The independent consultant's estimates of proved reserves and the pretax present value of such reserves discounted at 10% did not differ from our estimates by more than 1% in the aggregate. However, when compared on a lease-by-lease, field-by-field or area-by-area basis, some of our estimates may be greater than those of our independent consultant and some may be less than the estimates of the independent consultant. When such differences do not exceed 10% in the aggregate, our reserve auditor is satisfied that the proved reserves and pretax present value of such reserves discounted at 10% are reasonable and will issue an unqualified opinion. Remaining differences are not resolved due to the limited cost benefit of continuing such analysis. During the year, our reserves group also performs separate, detailed technical reviews of reserve estimates for significant acquisitions or for properties with problematic indicators such as excessively long lives, sudden changes in performance or changes in economic or operating conditions.

We have established and maintain internal controls designed to provide reasonable assurance that the estimates of proved reserves are computed and reported in accordance with rules and regulations promulgated by the SEC. These internal controls include documented process workflows, employing qualified engineering and geological personnel, and on-going education for personnel involved in our reserves estimation process. Our internal audit function routinely tests our processes and controls. Throughout the year, our technical team meets periodically with representatives of our independent petroleum consultants to review properties and discuss methods and assumptions. We provide historical information to our consultants for our largest producing properties such as ownership interest, natural gas, NGLs and oil production, well test data, commodity prices and operating and development costs. In some cases, additional meetings are held to review identified reserve differences.

All of our reserve estimates are reviewed with our executive management, our independent consultants perform an independent analysis, and ultimately our reserve estimates are approved by our Senior Vice President of Corporate Development, David J. Terry. Mr. Terry holds a Bachelor of Science degree in Petroleum Engineering from Louisiana State University and has more than fifteen years of engineering experience in the oil and gas industry.

We did not provide estimates of total proved oil and natural gas reserves during the three year period ended December 31, 2021 to any federal authority or agency, other than the SEC.

Production, Price and Cost Summary

Annual production, average prices that we realized from sales of natural gas and oil and the associated lifting costs for each of the last three fiscal years were as follows:

	Year Ended December 31,		
	2021	**2020**	**2019**
Net Production Volumes:			
Natural gas - Mcf	489,274	450,836	292,834
Oil - Bbl	1,210	1,508	2,685
Average Prices:			
Natural Gas - $/Mcf	$3.63	$1.80	$2.17
Oil - $/Bbl	$61.95	$32.36	$49.49
Lifting Costs - $/Mcfe:			
Lease operating	$0.21	$0.22	$0.27
Gathering and transportation	$0.26	$0.23	$0.23
Production and ad valorem taxes	$0.10	$0.08	$0.11

Drilling Activity Summary

During the three-year period ended December 31, 2021, we drilled development and exploratory wells as set forth in the table below:

	2021		2020		2019	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Oil	—	—	—	—	4	2.2
Gas	100	54.1	71	47.4	82	51.1
Dry	—	—	—	—	—	—
	100	54.1	71	47.4	86	53.3
Exploratory:						
Oil	—	—	—	—	—	—
Gas	—	—	—	—	—	—
Dry	—	—	—	—	—	—
	—	—	—	—	—	—
Total	100	54.1	71	47.4	86	53.3

As of December 31, 2021, 2020 and 2019, we had 28 (21.9 net), 26 (23.5 net), and 26 (18.1 net), respectively, operated wells in the process of being drilled and completed.

Producing Well Summary

The following table sets forth the gross and net producing oil and natural gas wells in which we owned an interest at December 31, 2021:

	Oil		Natural Gas	
	Gross	Net	Gross	Net
Louisiana	14	3.7	1,318	677.8
New Mexico	1	—	88	13.6
Oklahoma	6	0.6	99	8.9
Texas	15	6.8	990	746.3
Wyoming	—	—	26	1.9
Total	36	11.1	2,521	1,448.5

We operate 1,575 of the 2,557 producing wells presented in the above table. As of December 31, 2021, we did not own an interest in any wells containing multiple completions, which means that a well is producing from more than one completed zone.

Acreage

The following table summarizes our developed and undeveloped leasehold acreage at December 31, 2021, all of which is onshore in the continental United States. We have excluded acreage in which our interest is limited to a royalty or overriding royalty interest.

	Developed		Undeveloped	
	Gross	Net	Gross	Net
Louisiana	211,350	158,936	31,367	21,834
New Mexico	12,757	2,739	—	—
Oklahoma	26,080	3,382	—	—
Texas	234,362	161,240	135,303	93,962
Wyoming	13,440	927	—	—
Total	497,989	327,224	166,670	115,796

As of December 31, 2021, our undeveloped acreage expires as follows:

	Gross		Net	
2022	2,429	2 %	1,431	1 %
2023	5,562	3 %	4,740	4 %
2024	4,984	3 %	3,628	3 %
2025	30,787	18 %	23,983	21 %
2026	16,252	10 %	12,752	11 %
Thereafter	106,656	64 %	69,262	60 %
	166,670	100 %	115,796	100 %

Title to our oil and natural gas properties is subject to royalty, overriding royalty, carried and other similar interests and contractual arrangements customary in the oil and gas industry, liens incident to operating agreements and for current taxes not yet due and other minor encumbrances. All of our oil and natural gas properties are pledged as collateral under our bank credit facility. As is customary in the oil and natural gas industry, we are generally able to retain our ownership interest in undeveloped acreage by production from wells producing from a different reservoir, by drilling activity which establishes commercial reserves sufficient to maintain the lease, by payment of delay rentals or by the exercise of contractual extension rights.

Markets and Customers

The market for our production of oil and natural gas depends on factors beyond our control, including the extent of domestic production and imports of oil and natural gas, the proximity and capacity of natural gas pipelines and other transportation facilities, demand for oil and natural gas, the marketing of competitive fuels and the effects of state and federal regulation. The oil and natural gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers.

Our natural gas production is primarily sold under contracts with various terms and priced on first of the month index prices or on daily spot market prices. We target selling approximately 70% of our natural gas on first of month index price, with the remaining 30% on daily spot market pricing. The percentage of natural gas sold on spot market pricing can be impacted when new wells commence production as such production is typically sold on spot market pricing during the month the well is first brought on line. Enterprise Products Operating and its subsidiaries, Southwest Energy L.P. and Shell Oil Company and its subsidiaries accounted for 22%, 21%, and 13%, respectively, of our total 2021 sales. The loss of any of these customers would not have a material adverse effect on us as there is an available market for our crude oil and natural gas production from other purchasers.

We have entered into longer term marketing arrangements to ensure that we have adequate transportation to get our natural gas production in North Louisiana and East Texas to the markets. As an alternative to constructing our own gathering and treating facilities, we have entered into a variety of gathering and treating agreements with midstream companies to transport our natural gas to the long-haul natural gas pipelines. We currently have agreements with two major natural gas marketing companies to provide us with firm transportation for an average of approximately 690,000 MMBtu per day for our natural gas production in 2022 on the long-haul pipelines. To the extent we are not able to deliver the contracted natural gas volumes, we may be responsible for the transportation costs. Our production available to deliver under these agreements is expected to exceed the firm transportation arrangements we have in place. In addition, the marketing company managing the firm transportation is required to use reasonable efforts to supplement our deliveries should we have a shortfall during the term of the agreements.

Competition

The oil and gas industry is highly competitive. Competitors include major oil companies, other independent energy companies and individual producers and operators, many of which have financial resources, personnel and facilities substantially greater than we do. We face intense competition for the acquisition of oil and natural gas properties and leases for oil and gas exploration.

Regulation

General. Various aspects of our oil and natural gas operations are subject to extensive and continually changing regulation, as legislation affecting the oil and natural gas industry is under constant review for amendment or expansion. Numerous departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations binding upon the oil and natural gas industry and its individual members. The Federal Energy Regulatory Commission, or "FERC", regulates the transportation and sale for resale of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938, or "NGA", and the Natural Gas Policy Act of 1978, or "NGPA". In 1989, however, Congress enacted the Natural Gas Wellhead

Decontrol Act, which removed all remaining price and nonprice controls affecting all "first sales" of natural gas, effective January 1, 1993, subject to the terms of any private contracts that may be in effect. While sales by producers of natural gas and all sales of crude oil, condensate and natural gas liquids can currently be made at uncontrolled market prices, in the future Congress could reenact price controls or enact other legislation with detrimental impact on many aspects of our business. Under the provisions of the Energy Policy Act of 2005 (the "2005 Act"), the NGA has been amended to prohibit any form of market manipulation with the purchase or sale of natural gas, and the FERC has issued new regulations that are intended to increase natural gas pricing transparency. The 2005 Act has also significantly increased the penalties for violations of the NGA. The FERC has issued Order No. 704 et al. which requires a market participant to make an annual filing if it has sales or purchases equal to or greater than 2.2 million MMBtu in the reporting year to facilitate price transparency.

Regulation and transportation of natural gas. Our sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation are subject to extensive regulation. The FERC requires interstate pipelines to provide open-access transportation on a not unduly discriminatory basis for similarly situated shippers. The FERC frequently reviews and modifies its regulations regarding the transportation of natural gas, with the stated goal of fostering competition within the natural gas industry.

Intrastate natural gas transportation is subject to regulation by state regulatory agencies. The Texas Railroad Commission has been changing its regulations governing transportation and gathering services provided by intrastate pipelines and gatherers. While the changes by these state regulators affect us only indirectly, they are intended to further enhance competition in natural gas markets. We cannot predict what further action the FERC or state regulators will take on these matters; however, we do not believe that we will be affected differently in any material respect than other natural gas producers with which we compete by any action taken.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC, state commissions and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach pursued by the FERC, Congress and state regulatory authorities will continue.

Federal leases. Some of our operations are located on federal oil and natural gas leases that are administered by the Bureau of Land Management ("BLM") of the United States Department of the Interior. These leases are issued through competitive bidding and contain relatively standardized terms. These leases require compliance with detailed Department of Interior and BLM regulations and orders that are subject to interpretation and change. These leases are also subject to certain regulations and orders promulgated by the Department of Interior's Bureau of Ocean Energy Management, Regulation & Enforcement ("BOEMRE"), through its Minerals Revenue Management Program, which is responsible for the management of revenues from both onshore and offshore leases. The Company's operations located on federal oil and natural gas leases are insignificant to its total operations and any Executive Orders related to federal oil and gas leases issued by the Biden administration are not expected to adversely affect our business, financial position and results of operations.

Oil and natural gas liquids transportation rates. Our sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act. In other instances, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes. The price received from the sale of these products may be affected by the cost of transporting the products to market.

The FERC's regulation of pipelines that transport crude oil, condensate and natural gas liquids under the Interstate Commerce Act is generally more light-handed than the FERC's regulation of natural gas pipelines under the NGA. FERC-regulated pipelines that transport crude oil, condensate and natural gas liquids are subject to common carrier obligations that generally ensure non-discriminatory access. With respect to interstate pipeline transportation subject to regulation of the FERC under the Interstate Commerce Act, rates generally must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates are permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates governed by the Interstate Commerce Act that allowed for an increase or decrease in the transportation rates. The FERC's regulations include a methodology for such pipelines to change their rates through the use of an index system that establishes ceiling levels for such rates. The mandatory five year review in 2005 revised the methodology for this index to be based on Producer Price Index for Finished Goods (PPI-FG) plus 1.3 percent for the period July 1, 2006 through June 30, 2011. The mandatory five year review in 2012 revised the methodology for this index to be based on PPI-FG plus 2.65 percent for the period July 1, 2011 through June 30, 2016. The regulations provide that each year the Commission will publish the oil pipeline index after the PPI-FG becomes available.

With respect to intrastate crude oil, condensate and natural gas liquids pipelines subject to the jurisdiction of state agencies, such state regulation is generally less rigorous than the regulation of interstate pipelines. State agencies have generally not investigated or challenged existing or proposed rates in the absence of shipper complaints or protests. Complaints or protests have been infrequent and are usually resolved informally.

We do not believe that the regulatory decisions or activities relating to interstate or intrastate crude oil, condensate or natural gas liquids pipelines will affect us in a way that materially differs from the way it affects other crude oil, condensate and natural gas liquids producers or marketers.

Environmental regulations. We are subject to stringent federal, state and local laws. These laws, among other things, govern the issuance of permits to conduct exploration, drilling and production operations, the amounts and types of materials that may be released into the environment, the discharge and disposition of waste materials, the remediation of contaminated sites and the reclamation and abandonment of wells, sites and facilities. Numerous governmental departments issue rules and regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial civil and even criminal penalties for failure to comply. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose strict liability for environmental contamination, rendering a person liable for environmental damages and cleanup cost without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and natural gas production below the rate that would otherwise exist or even prohibit exploration and production activities in sensitive areas. In addition, state laws often require various forms of remedial action to prevent pollution, such as closure of inactive pits and plugging of abandoned wells. The regulatory burden on the oil and natural gas industry increases our cost of doing business and consequently affects our profitability. These costs are considered a normal, recurring cost of our on-going operations. Our domestic competitors are generally subject to the same laws and regulations.

We believe that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on our operations. Environmental laws and regulations have been subject to frequent changes over the years, and the imposition of more stringent requirements or new regulatory schemes such as carbon "cap and trade" or pricing programs could have a material adverse effect upon our capital expenditures, earnings or competitive position, including the suspension or cessation of operations in affected areas. The Biden administration has made, and is expected to make additional changes to applicable regulations, and in each case we expect changes to be more stringent than those of the prior administration. There are also costs associated with responding to changing regulations and policies, whether such regulations are more or less stringent. As such, there can be no assurance that material cost and liabilities will not be incurred in the future.

The Comprehensive Environmental Response, Compensation and Liability Act; or "CERCLA", imposes liability, without regard to fault, on certain classes of persons that are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the current or former owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances. Under CERCLA, such persons may be subject to joint and several liability for the cost of investigating and cleaning up hazardous substances that have been released into the environment, for damages to natural resources and for the cost of certain health studies. In addition, companies that incur liability frequently also confront third party claims because it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment from a polluted site. Many states have adopted similar statutes that impose liability for the release of hazardous substances and petroleum. In addition, from time to time the EPA, states, and other agencies make new findings that certain chemicals are potential environmental concerns, sometimes referred to as emerging contaminants. These agencies may also adjust risk based assessment or cleanup levels, in some instances, to be more stringent. The EPA and other agencies may impose new restrictions or cleanup requirements on such chemicals. We may incur costs to comply with such requirements.

The Federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, or "RCRA", regulates the generation, transportation, storage, treatment and disposal of hazardous wastes and can require cleanup of hazardous waste disposal sites. RCRA currently excludes drilling fluids, produced waters and other wastes associated with the exploration, development or production of oil and natural gas from regulation as "hazardous waste". Disposal of such non-hazardous oil and natural gas exploration, development and production wastes usually are regulated by state law. Other wastes handled at exploration and production sites or used in the course of providing well services may not fall within this exclusion. Moreover, stricter standards for waste handling and disposal may be imposed on the oil and natural gas industry in the future. From time to time, legislation is proposed in Congress that would revoke or alter the current exclusion of exploration, development and production wastes from RCRA's definition of "hazardous wastes", thereby potentially subjecting such wastes to more stringent handling, disposal and cleanup requirements. If such legislation were enacted, it could have a significant impact on our operating costs, as well as the oil and natural gas industry in general. The impact of future revisions to environmental laws and regulations cannot be predicted.

Certain oil and gas wastes may also contain naturally occurring radioactive material ("NORM"), which is regulated by the federal Occupational Safety and Health Administration and state agencies. These regulations require certain worker protections and waste handling and disposal procedures. We believe our operations comply in all material respects with these worker protection and waste handling and disposal requirements.

Our operations are also subject to the Clean Air Act, or "CAA", and comparable state and local requirements. Amendments to the CAA were adopted in 1990 and contain provisions that may result in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. Between 2012 and 2014, the U.S. Environmental Protection Agency or "EPA" promulgated new emission standards for the oil and natural gas industry, and made revisions that imposed further requirements with respect to volatile organic compounds ("VOCs") and methane. In September 2020, the EPA published a rule that revised the VOC requirements and rescinded the methane requirements, as well as revised its interpretation of the CAA, such that, in order to impose the methane emission requirements, it would need to first make a Significant Contribution Finding for each particular pollutant for the specific source. Since that time, the US has passed a law that repeals the 2020 rules, and the EPA issued a new proposed rule as of November 2021. The comment period for this rule has been extended through January 31, 2022. The EPA also announced it expects further technical revisions in the coming year. We expect such changes to apply to our operations. There are costs associated with following the status and impacts of these regulatory changes, and implementing any changes as they become effective. However, we believe our operations will not be materially adversely affected by new or reinstated requirements, and the requirements are not expected to be any more burdensome to us than to other similarly situated companies involved in oil and natural gas exploration and production activities.

The Federal Water Pollution Control Act of 1972, as amended, or the "Clean Water Act", imposes restrictions and controls on the discharge of produced waters and other wastes into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. Recent judicial interpretations have caused certain water features to be considered jurisdictional when they were not previously. Additionally, the EPA and the US Army Corps of Engineers recently issued a proposed rule that would revise the definition of "waters of the United States" to return to the pre-2017 definition. If passed, such regulations may impact certain exploration and production activities. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into certain coastal and offshore waters, unless otherwise authorized. Further, the EPA has adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. The Clean Water Act and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges for oil and other pollutants and impose liability on parties responsible for those discharges for the cost of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. We believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution.

The Federal Safe Drinking Water Act of 1974, as amended, requires the EPA to develop minimum federal requirements for Underground Injection Control ("UIC") programs and other safeguards to protect public health by preventing injection wells from contaminating underground sources of drinking water. The UIC program does not regulate wells that are solely used for production. However, the EPA has authority to regulate hydraulic fracturing when diesel fuels are used in fluids or propping agents. In February 2014, the EPA issued guidance on when UIC permitting requirements apply to fracking fluids containing diesel. We believe that our operations comply in all material respects with the requirements of the Federal Safe Drinking Water Act and similar state statutes. We believe the requirements are not any more burdensome to us than to other similarly situated companies involved in oil and natural gas exploration and production activities.

State and federal regulatory agencies have studied possible connections between hydraulic fracturing related activities and the increased occurrence of seismic activity. When caused by human activity, such events are called induced seismicity. In a few instances, operators of injection wells in the vicinity of seismic events have been ordered to reduce injection volumes or suspend operations. Some state regulatory agencies, including those in Arkansas, California, Colorado, Illinois, Kansas, Ohio, Oklahoma, and Texas, have modified their regulations to account for induced seismicity. There continues to be research into the possible linkage between oil and natural gas activity and induced seismicity. A 2012 report published by the National Academy of Sciences, as well as a more recent paper published in the journal Reviews of Geophysics and cited on the US Geological Survey website, concluded that only a very small fraction of the tens of thousands of injection wells have been suspected to be, or have been, the likely cause of induced seismicity. In 2015, the United States Geological Survey identified eight states, including Texas, with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and natural gas extraction. In March 2016, the United States Geological Survey identified six states with the most significant hazards from induced seismicity, including Texas, Colorado, Oklahoma, Kansas, New Mexico, and Arkansas. In addition, a number of lawsuits have been filed, including in Oklahoma, alleging that disposal well operations have caused damage to or injury at nearby properties or otherwise violated state and federal rules regulating waste disposal. It is possible that the EPA or other agencies may develop rules to specifically address the disposal of wastewater from oil and natural gas development and the potential for induced seismicity from wastewater injection. Future regulatory developments could adversely affect our operations by placing restrictions on the use of injection wells and hydraulic fracturing and/or causing us to incur increased operating expenses.

In December 2016, the EPA finalized its report on the potential impacts of hydraulic fracturing on drinking water resources, which concluded that hydraulic fracturing activities could impact drinking water resources under some circumstances. Other governmental agencies, including the U.S. Department of Energy, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies have the potential to impact the likelihood or scope of future legislation or regulation.

Federal regulators require certain owners or operators of facilities that store or otherwise handle oil to prepare and implement spill prevention, control, countermeasure and response plans relating to the possible discharge of oil into surface waters. The Oil Pollution Act of 1990 ("OPA") contains numerous requirements relating to the prevention and response to oil spills in the waters of the United States. The OPA subjects owners of facilities to strict joint and several liability for all containment and cleanup costs and certain other damages relating to a spill. Noncompliance with OPA may result in varying civil and criminal penalties and liabilities.

Executive Order 13158, issued on May 26, 2000, directs federal agencies to safeguard existing Marine Protected Areas, or MPAs, in the United States and establish new MPAs. The order requires federal agencies to avoid harm to MPAs to the extent permitted by law and to the maximum extent practicable. It also directs the EPA to propose new regulations under the Clean Water Act to ensure appropriate levels of protection for the marine environment. This order has the potential to adversely affect our operations by restricting areas in which we may carry out future exploration and development projects and/or causing us to incur increased operating expenses.

Certain flora and fauna that have officially been classified as "threatened" or "endangered" are protected by the Endangered Species Act. This law prohibits any activities that could "take" a protected plant or animal or reduce or degrade its habitat area. If endangered species are located in an area we wish to develop, the work could be prohibited or delayed and/or expensive mitigation might be required.

Other statutes that provide protection to animal and plant species and which may apply to our operations include, but are not necessarily limited to, the Oil Pollution Act, the Emergency Planning and Community Right to Know Act, the Marine Mammal Protection Act, the Marine Protection, Research and Sanctuaries Act, the Fish and Wildlife Coordination Act, the Fishery Conservation and Management Act, the Migratory Bird Treaty Act and the National Historic Preservation Act. These laws and regulations may require the acquisition of a permit or other authorization before construction or drilling commences and may limit or prohibit construction, drilling and other activities on certain lands lying within wilderness or wetlands and other protected areas and impose substantial liabilities for pollution resulting from our operations. The permits required for our various operations are subject to revocation, modification and renewal by issuing authorities. In addition, laws such as the National Environmental Policy Act and the Coastal Zone Management Act may make the process of obtaining certain permits more difficult or time consuming, resulting in increased costs and potential delays that could affect the viability or profitability of certain activities. Administrative policies with respect to such laws are also changing, and we incur costs to follow such changes and comply as changes become effective.

Certain statutes such as the Emergency Planning and Community Right to Know Act require the reporting of hazardous chemicals manufactured, processed, or otherwise used, which may lead to heightened scrutiny of the company's operations by regulatory agencies or the public. In 2012, the EPA adopted a new reporting requirement, the Petroleum and Natural Gas Systems Greenhouse Gas Reporting Rule (40 C.F.R. Part 98, Subpart W), which requires certain onshore petroleum and natural gas facilities to begin collecting data on their emissions of greenhouse gases ("GHG") in January 2012, with the first annual reports of those emissions due on September 28, 2012. GHGs include gases such as methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning natural gas. Different GHGs have different global warming potentials with CO2 having the lowest global warming potential, so emissions of GHGs are typically expressed in terms of CO2 equivalents, or CO2e. The rule applies to facilities that emit 25,000 metric tons of CO2e or more per year, and requires onshore petroleum and natural gas operators to group all equipment under common ownership or control within a single hydrocarbon basin together when determining if the threshold is met. These greenhouse gas reporting rules were amended on October 22, 2015 to expand the number of sources and operations that are subject to these rules, and again on November 18, 2016 to provide less burdensome reporting requirements. We have determined that these reporting requirements apply to us and we believe we have met all of the EPA required reporting deadlines and strive to ensure accurate and consistent emissions data reporting. It is possible that these requirements may be more restrictive under the Biden administration. Other EPA actions with respect to the reduction of greenhouse gases (such as the EPA's Greenhouse Gas Endangerment Finding, and the EPA's Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule) and various state actions have or could impose mandatory reductions in greenhouse gas emissions. We are unable to predict at this time how much the cost of compliance with any legislation or regulation of greenhouse gas emissions will be in future periods.

The U.S. has not passed legislation to expressly address GHGs; however, in recent years the EPA moved ahead with its efforts to regulate GHG emissions from certain sources by rule. Beyond requiring measurement and reporting of GHGs as discussed above, the EPA issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The EPA has adopted regulations that would require permits for and reductions in greenhouse gas emissions for certain facilities. States in which we operate may also require permits and reductions in GHG emissions. Additionally, the EPA published a set of final rules in 2016 that require reductions in VOC and methane generation from new sources. Although 2020 rule changes reduced these requirements, the EPA has and is expected to issue additional proposed regulations in response to Executive Orders issued by the Biden administration. Other additional regulations may still be forthcoming. Similarly, the Bureau of Land Management ("BLM") has proposed to suspend and revise a 2016 rule relating to methane venting, flaring, and leaks from oil and natural gas production on public lands that was being challenged by multiple western states and energy companies. In September 2018, the BLM published a final rule revising or rescinding certain provisions of the 2016 rule. The 2018 rule was challenged in federal court, and was vacated in 2020, but the court stayed its vacatur of the 2018 rule to allow for challenges to the 2016 rule to proceed. BLM did not defend the 2016 rule, and it was vacated. This decision may be further appealed, leaving the final outcome uncertain. Since all of our oil and natural gas production is in the United States, laws or regulations that have been or may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur substantial increased operating costs, and could have an adverse effect on demand for the oil and natural gas we produce. In addition, efforts have been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues. Most recently in 2015, the United States participated in the United Nations Conference on Climate Change, which led to the creation of the Paris Agreement. The Paris Agreement requires ratifying countries to review and "represent a progression" in the ambitions of their nationally determined contributions, which set GHG emission reduction goals, every five years. The United States signed the Paris Agreement on April 22, 2016; although the Trump administration provided notice of its intent to withdraw from the Paris Agreement, the Biden administration has reinstated the United States' participation. Further, the US has made additional commitments with respect to GHG emissions through the United Nations Climate Change Conference, including with respect to reducing methane emissions. It is difficult to predict the timing and certainty of any future government action and the effect on our operations. Future legislation or regulations adopted to address climate change could also make our products more or less desirable than competing sources of energy. However, we expect that the impacts to our operations will not be materially different from other similarly situated companies involved in oil and natural gas exploration and production activities.

In 2010, the BLM began implementation of a proposed oil and natural gas leasing reform that would increase environmental review requirements and was expected to have the effect of reducing the amount of new federal lands made available for lease, increasing the competition for and cost of available parcels. This leasing reform initiative was replaced by a new BLM policy, dated January 31, 2018, which is expected to remove the additional environmental review created under the 2010 initiative and streamline the leasing process. Additionally, on December 28, 2017, the BLM rescinded a rule the BLM adopted in 2015 concerning hydraulic fracturing on federal land. The 2015 rule would have required increased well integrity testing, increased requirements for the managing of fluids, and the disclosure of chemicals used in fracturing. The Biden administration issued an Executive Order pausing new oil and natural gas leasing and drilling permits for U.S. public lands and offshore waters until the Secretary of the Interior conducts a comprehensive review and reconsideration of Federal oil and natural gas permitting and leasing practices. Further actions may occur. Due to the ongoing regulatory and legal uncertainty, we cannot predict what effect these changes will have on our operations, though the changes are expected to be more restrictive with regard to oil and natural gas leasing on Federal lands in the future. We expect that the impacts to our operations will be similar to other similarly situated companies involved in oil and natural gas exploration and production activities.

Such changes in environmental laws and regulations which result in more stringent and costly reporting, or waste handling, storage, transportation, disposal or cleanup activities, could materially affect companies operating in the energy industry. Adoption of new regulations further regulating emissions from oil and gas production could adversely affect our business, financial position, results of operations and prospects, as could the adoption of new laws or regulations which levy taxes or other costs on greenhouse gas emissions from other industries, which could result in changes to the consumption and demand for natural gas. We may also be assessed administrative, civil and/or criminal penalties if we fail to comply with any such new laws and regulations applicable to oil and natural gas production.

Regulation of oil and natural gas exploration and production. Our exploration and production operations are subject to various types of regulation at the federal, state and local levels. Such regulations include requiring permits and drilling bonds for the drilling of wells, regulating the location of wells, the method of drilling and casing wells and the surface use and restoration of properties upon which wells are drilled. Many states also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells and the regulation of spacing, plugging and abandonment of such wells. Some state statutes limit the rate at which oil and natural gas can be produced from our properties. It is also possible that certain states may increase regulatory activity in response to changing federal regulations or policies.

State regulation. Most states regulate the production and sale of oil and natural gas, including requirements for obtaining drilling permits, the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and natural gas resources. The rate of production may be regulated and the maximum daily production allowable from both oil and natural gas wells may be established on a market demand or conservation basis or both.

Office and Operations Facilities

Our executive offices are located at 5300 Town and Country Blvd., Suite 500 in Frisco, Texas 75034 and our telephone number is (972) 668-8800. We lease office space in Frisco, Texas covering 66,382 square feet. This lease expires on December 31, 2024. We also own production offices and pipe yard facilities near Carthage, Franklin, Nacogdoches and Marshall, Texas and Bossier City, Grand Cane, Greenwood, Homer and Logansport, Louisiana.

Human Capital

As of December 31, 2021, we had 205 employees and utilized contract employees for certain of our drilling, completion and production operations. We seek to attract a qualified and diverse workforce and maintain strong non-discrimination and anti-harassment policies.

The safety of our employees, contractors and the community is a core business value and in order to obtain our goals of operational excellence and an injury free workplace, we maintain a strong health and safety management system. The framework includes policies and procedures outlining how we do our work, programs to engage employees and drive a proactive safety culture, employee training to help ensure our employees have the knowledge to perform their work safely, setting targets and objectives for clearly defined deliverables and accountabilities and periodic audit and inspection of results using data collection of key performance indicators and scorecards to measure our success and develop improvement strategies. In response to the COVID-19 pandemic, we have implemented a COVID-19 exposure prevention, preparedness and response plan that incorporates the latest information available from public officials.

We utilize a third party contractor management service to ensure a consistent approach in aligning our expectations with all third parties involved in our operations. We hold our contractors accountable to the highest performance standards through our contractor onboarding and continuous auditing process.

Directors and Executive Officers

The following table sets forth certain information concerning our executive officers and directors.

Name	Position with Company	Age
M. Jay Allison	Chief Executive Officer and Chairman of the Board of Directors	66
Roland O. Burns	President, Chief Financial Officer, Secretary and Director	61
Daniel S. Harrison	Chief Operating Officer	58
David J. Terry	Senior Vice President of Corporate Development	41
Patrick H. McGough	Vice President of Operations	41
Ronald E. Mills	Vice President of Finance and Investor Relations	50
Daniel K. Presley	Vice President of Accounting, Controller and Treasurer	61
LaRae L. Sanders	Vice President of Land	59
Whitney H. Ward	Vice President of Marketing	37
Brian C. Claunch	Vice President of Financial Reporting	47
Elizabeth B. Davis	Director	59
Morris E. Foster	Director	79
Jim L. Turner	Director	76

A brief biography of each person who serves as an executive officer or director follows below.

Executive Officers

M. Jay Allison has been our Chief Executive Officer since 1988. Mr. Allison was elected Chairman of the Board in 1997 and has been a director since 1987. From 1988 to 2013, Mr. Allison served as our President. From 1981 to 1987, he was a practicing oil and gas attorney with the firm of Lynch, Chappell & Alsup in Midland, Texas. He received B.B.A., M.S. and J.D. degrees from Baylor University in 1978, 1980 and 1981, respectively.

Roland O. Burns has been our President since 2013, Chief Financial Officer since 1990, Secretary since 1991 and a director since 1999. Mr. Burns served as our Senior Vice President from 1994 to 2013 and Treasurer from 1990 to 2013. From

1982 to 1990, Mr. Burns was employed by the public accounting firm, Arthur Andersen. During his tenure with Arthur Andersen, Mr. Burns worked primarily in the firm's oil and gas audit practice. Mr. Burns received B.A. and M.A. degrees from the University of Mississippi in 1982 and is a Certified Public Accountant. Mr. Burns also serves on the Board of Directors and the audit committee of the University of Mississippi Foundation.

Daniel S. Harrison became our Chief Operating Officer in July 2019 and served as Vice President of Operations since 2017. Mr. Harrison has been with us since 2008 and served in various engineering and operations management positions of increasing responsibility during that time. Prior to joining us, Mr. Harrison was an operations engineer at Cimarex Energy Company from 2005 to 2008. Prior to 2005 he worked in various petroleum engineering operations management positions for several independent oil and gas exploration and development companies. Mr. Harrison received a B.S. Degree in Petroleum Engineering from the Louisiana State University in 1985.

David J. Terry became our Senior Vice President of Corporate Development in July 2019 concurrently with the closing of the Covey Park Acquisition. In this role, Mr. Terry is responsible for driving our long-term strategy for acquisitions and development, reserves and midstream. Prior to co-founding Covey Park, Mr. Terry held significant roles in operations and business development at EXCO Resources, Inc. and Winchester Production. Mr. Terry received a Bachelor of Science in Petroleum Engineering from Louisiana State University in 2005.

Patrick H. McGough became our Vice President of Operations in July 2019 following the Covey Park Acquisition. He joined Covey Park in August 2018 as the Vice President of Operations, where he was responsible for drilling, completion, and production operations and engineering. Prior to his time at Covey Park, Mr. McGough held significant roles as a drilling, completion, and production engineer at Brammer Engineering. Mr. McGough received a Bachelor of Science in Chemical Engineering from Louisiana Tech University in 2003 and an MBA from Centenary College of Louisiana in 2010.

Ronald E. Mills became our Vice President of Finance and Investor Relations in August 2019. Prior to joining us, Mr. Mills was an Equity Member and Senior Analyst responsible for covering exploration and production companies at Johnson Rice & Company LLC. Mr. Mills joined Johnson Rice in August 1995. Mr. Mills received a Bachelor of Arts in Economics and Master of Business Administration from Tulane University in 1994 and 1995, respectively.

Daniel K. Presley has been our Treasurer since 2013. Mr. Presley, who has been with us since 1989, also continues to serve as our Vice President of Accounting and Controller, positions he has had held since 1997 and 1991, respectively. Prior to joining us, Mr. Presley had six years of experience with several independent oil and gas companies including AmBrit Energy, Inc. Prior thereto, Mr. Presley spent two and one-half years with B.D.O. Seidman, a public accounting firm. Mr. Presley received a B.B.A. degree from Texas A & M University in 1983.

LaRae L. Sanders has been our Vice President of Land since 2014. Ms. Sanders has been with us since 1995. She has served as Land Manager since 2007, and has been instrumental in all of our active development programs and major acquisitions. Prior to joining us, Ms. Sanders held positions with Bridge Oil Company and Kaiser-Francis Oil Company, as well as other independent exploration and production companies. Ms. Sanders is a Certified Professional Landman with 38 years of experience. She became the nation's first Certified Professional Lease and Title Analyst in 1990.

Whitney H. Ward became our Vice President of Marketing in July 2019 concurrently with the closing of the Covey Park Acquisition, where she also served as Vice President of Marketing. She joined Covey Park in 2014, and started the marketing department. Prior to joining Covey Park, Ms. Ward held various positions in the marketing department at EXCO Resources, Inc. from 2007 through 2014. She received a Bachelor's degree in Communication Studies from The University of Texas at Austin in 2007.

Brian C. Claunch became our Vice President of Financial Reporting in June 2021. Mr. Claunch joined the Company in June 2020 as Director of Financial Reporting. Prior to joining Comstock, Mr. Claunch served as Director of Financial Reporting at Guidon Energy and Controller at Pioneer Natural Resources Company. He received his Bachelors of Business Administration and Masters of Science in Accounting degrees from the University of Texas at Arlington in 1999.

Outside Directors

Elizabeth B. Davis has served as a director since 2014. Dr. Davis is currently the President of Furman University. Dr. Davis was the Executive Vice President and Provost for Baylor University until July 2014, and served as Interim Provost from 2008 until 2010. Prior to her appointment as Provost, she was a professor of accounting in the Hankamer School of Business at Baylor University where she also served as associate dean for undergraduate programs and as acting chair for the Department of Accounting and Business Law. Prior to joining Baylor University, she worked for the public accounting firm Arthur Andersen from 1984 to 1987.

Morris E. Foster has served as a director since 2017. Mr. Morris retired in 2008 as Vice President of ExxonMobil Corporation and President of ExxonMobil Production Company following more than 40 years of service with the ExxonMobil group. Mr. Foster served in a number of production engineering and management roles domestically as well as in the United Kingdom and Malaysia prior to his appointment in 1995 as a Senior Vice President in charge of the upstream business of Exxon Company, USA. In 1998, Mr. Foster was appointed President of Exxon Upstream Development Company, and following the merger of Exxon and Mobil in 1999, he was named to the position of President of ExxonMobil Development Company. In 2004, Mr. Foster was named President of Exxon Mobil Production Company, the division responsible for ExxonMobil's upstream oil and gas exploration and production business, and a Vice President of ExxonMobil Corporation. Mr. Foster currently serves as Chairman of Stagecoach Properties Inc., a real estate holding corporation with properties in Salado, Houston and College Station, Texas and Carmel, California and as a member of the Board of Regents of Texas A&M University. In addition, Mr. Foster currently serves on the board of directors of Scott & White Medical Institute.

Jim L. Turner has served as a director since 2014. Mr. Turner currently serves as Chairman of Turner Holdings, LLC and CEO of JLT Automotive, Inc. Mr. Turner served as President and Chief Executive Officer of Dr Pepper/Seven Up Bottling Group, Inc. from its formation in 1999 through 2005, when he sold this interest in that company. Prior to that, Mr. Turner served as Owner/Chairman of the Board and Chief Executive Officer of the Turner Beverage Group, the largest privately owned independent bottler in the United States. Mr. Turner is past-Chairman and currently serves on the Board of Trustees of Baylor Scott and White Health, the largest not-for-profit healthcare system in the State of Texas, where he also serves as Chairman of the Finance Committee and as a member of the Executive Committee. He is a Director of Crown Holdings where he also serves as Chairman of the Compensation Committee and as a member of the Nominating and Governance Committee. He is on the Board of Directors of INSURICA, a full service insurance agency. Mr. Turner is former Chairman of Dean Foods Company where he also served as Chairman of the Compensation Committee.

Available Information

We file annual, quarterly and current reports, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934. The SEC maintains a website that contains reports, proxy and information statements, and other information that is electronically filed with the SEC. The public can obtain any documents that we file with the SEC at www.sec.gov. We also make available free of charge on our website (www.comstockresources.com) our Annual Report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after we file such material with, or furnish it to, the SEC.

ITEM 1A. *Risk Factors*

You should carefully consider the following material risk factors as well as the other information contained or incorporated by reference in this report, as these important factors, among others, could cause our actual results to differ from our expected or historical results. It is not possible to predict or identify all such factors. Consequently, you should not consider any such list to be a complete statement of all of our potential risks or uncertainties. Based on the information currently known to us, we believe the following information identifies the most material risk factors affecting us, but the below risks and uncertainties are not the only ones related to our businesses and are not necessarily listed in the order of their significance. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also adversely affect our business.

An extended period of depressed oil and natural gas prices would adversely affect our business, financial condition, cash flow, liquidity, results of operations and our ability to meet our capital expenditure obligations and financial commitments.

Our business is heavily dependent upon the price of, and demand for, natural gas. Historically, natural gas prices have been volatile and are likely to remain volatile in the future. The prices we receive for our natural gas production depend on numerous factors beyond our control, including the following:

- the domestic and foreign supply of natural gas;
- weather conditions;
- the price and quantity of exports of natural gas;
- political conditions and events in other oil-producing and natural gas-producing countries, including embargoes, hostilities in the Middle East and other sustained military campaigns, and acts of terrorism or sabotage;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- domestic government regulation, legislation and policies;
- the level of global natural gas inventories;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels; and
- overall economic conditions.

Lower natural gas prices will adversely affect:

- our revenues, profitability and cash flow from operations;
- the value of our proved natural gas reserves;
- the economic viability of certain of our drilling prospects;
- our borrowing capacity; and
- our ability to obtain additional capital.

Our future production and revenues depend on our ability to replace our reserves.

Our future production and revenues depend upon our ability to find, develop or acquire additional natural gas reserves that are economically recoverable. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful drilling activities or acquire properties containing proved reserves, or both. To increase reserves and production, we must continue our acquisition and drilling activities. We cannot assure you that we will have adequate capital resources to conduct acquisition and drilling activities or that our acquisition and drilling activities will result in significant additional reserves or that we will have continuing success drilling productive wells at low finding and development costs. Furthermore, while our revenues may increase if prevailing oil and natural gas prices increase significantly, our finding costs for additional reserves could also increase.

Our hedging transactions could result in financial losses or could reduce our income. To the extent we have hedged a significant portion of our expected production and our actual production is lower than we expected or the costs of goods and services increase, our profitability would be adversely affected.

To achieve more predictable cash flows and to reduce our exposure to adverse fluctuations in the prices of natural gas, we have entered into and may continue to enter into hedging transactions for certain of our expected natural gas production. These transactions could result in both realized and unrealized hedging losses. Further, these hedges may be inadequate to protect us from continuing and prolonged declines in the price of natural gas. To the extent that the natural gas prices remain at current levels or declines further, we will not be able to hedge future production at the same level as our current hedges, and our results of operations and financial condition would be negatively impacted.

The extent of our commodity price exposure is related largely to the effectiveness and scope of our derivative activities. For example, the derivative instruments we utilize are primarily based on NYMEX futures prices, which may differ significantly from the actual natural gas prices we realize in our operations. Furthermore, we have adopted a policy that requires, and our revolving credit facility also requires, that we enter into derivative transactions related to only a portion of our expected production volumes and, as a result, we will continue to have direct commodity price exposure on the portion of our production volumes not covered by these derivative financial instruments.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into derivative transactions. If our actual future production is higher than we estimated, we will have greater commodity price exposure than we intended. If our actual future production is lower than the nominal amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, resulting in a substantial diminution in our profitability and liquidity. As a result of these factors, our derivative activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows.

In addition, our hedging transactions are subject to the following risks:

- we may be limited in receiving the full benefit of increases in natural gas prices as a result of these transactions;
- a counterparty may not perform its obligation under the applicable derivative financial instrument or may seek bankruptcy protection;
- there may be a change in the expected differential between the underlying commodity price in the derivative instrument and the actual price received; and
- the steps we take to monitor our derivative financial instruments may not detect and prevent violations of our risk management policies and procedures, particularly if deception or other intentional misconduct is involved.

Our operations may incur substantial liabilities due to compliance with environmental laws and regulations.

We are subject to stringent federal, state and local laws. These laws, among other things, govern the issuance of permits to conduct exploration, drilling and production operations, the amounts and types of materials that may be released into the environment, the discharge and disposition of waste materials, the remediation of contaminated sites and the reclamation and abandonment of wells, sites and facilities. Numerous governmental departments issue rules and regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial civil and even criminal penalties for failure to comply. The regulatory burden on the oil and natural gas industry from these environmental laws and regulations increases our cost of doing business and consequently affects our profitability.

Environmental laws and regulations have been subject to frequent changes over the years, and the imposition of more stringent requirements or new regulatory schemes such as carbon "cap and trade" or pricing programs could have a material adverse effect upon our capital expenditures, earnings or competitive position, including the suspension or cessation of operations in affected areas.

We may be subject to physical and financial risks associated with climate change.

Changing climate may create physical and financial risks to our business. Energy needs vary with weather conditions. To the extent weather conditions may be affected by climate change, energy use could increase or decrease depending on the duration and magnitude of any changes. Increased energy use due to weather changes may require us to invest in more infrastructure to serve increased demand. A decrease in energy use due to weather changes may affect our financial condition through decreased revenues. Extreme weather conditions in general require more equipment redundancy, adding to costs, and can contribute to increased risk of delivery disruptions.

Additionally, many climate models indicate that global warming is likely to result in rising sea levels and increased frequency and severity of weather events, which may lead to higher insurance costs, or a decrease in available coverage, for our assets in areas subject to severe weather. These climate-related changes could damage our physical assets, especially operations located in low-lying areas near coasts and river banks, and facilities situated in hurricane-prone and rain-susceptible regions. To the extent the frequency of extreme weather events increases, this could increase our cost of producing products. We may not be able to pass on the higher costs to our customers or recover all costs related to mitigating these physical risks.

Regulations relating to climate change and/or greenhouse gases could also reduce demand for our products or increase our operating and drilling costs. Our business could also be affected by the potential for lawsuits against companies that emit greenhouse gases, based on links drawn between greenhouse gas emissions and climate change. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of and access to capital.

Increasing scrutiny and changing expectations from stakeholders with respect to our environmental, social and governance practices may impose additional costs on us or expose us to new or additional risks.

Companies across all industries are facing increasing scrutiny from stakeholders related to their environmental, social and governance ("ESG") practices. Investor advocacy groups, certain institutional investors, investment funds and other influential investors are also increasingly focused on ESG practices and in recent years have placed increasing importance on the implications and social cost of their investments. Regardless of the industry, investors' increased focus and activism related to ESG and similar matters may hinder access to capital, as investors may decide to reallocate capital or to not commit capital as a result of their assessment of a company's ESG practices. Companies that do not adapt to or comply with investor or other stakeholder expectations and standards, which are evolving, or that are perceived to have not responded appropriately to the growing concern for ESG issues, regardless of whether there is a legal requirement to do so, may suffer from reputational damage and the business, financial condition, and/or stock price of such a company could be materially and adversely affected.

We face pressures from our stockholders, who are increasingly focused on climate change, to prioritize sustainable energy practices, reduce our carbon footprint and promote sustainability. Our stockholders may require us to implement new ESG procedures or standards in order to continue engaging with us, to remain invested in us or before they may make further investments in us. Additionally, we may face reputational challenges in the event our ESG procedures or standards do not meet the standards set by certain constituencies. We have adopted certain practices and metrics as highlighted on our website, including with respect to air emissions, land use, environmental, health and safety management and corporate governance. It is possible, however, that our stockholders might not be satisfied with our sustainability efforts or the speed of their adoption. If we do not meet our stockholders' expectations, our business, ability to access capital, and/or our stock price could be harmed.

Additionally, adverse effects upon the oil and gas industry related to the worldwide social and political environment, including uncertainty or instability resulting from climate change, changes in political leadership and environmental policies, changes in geopolitical-social views toward fossil fuels and renewable energy, concern about the environmental impact of climate change, and investors' expectations regarding ESG matters, may also adversely affect demand for our products. Any long-term material adverse effect on the oil and natural gas industry could have a significant financial and operational adverse impact on our business.

The occurrence of any of the foregoing could have a material adverse effect on the price of our stock and our business and financial condition.

Substantial exploration and development activities could require significant outside capital, which could dilute the value of our common shares and restrict our activities. Also, we may not be able to obtain needed capital or financing on satisfactory terms, which could lead to a limitation of our future business opportunities and a decline in our oil and natural gas reserves.

We expect to expend substantial capital in the acquisition of, exploration for and development of natural gas reserves. In order to finance these activities, we may need to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of non-strategic assets or other means. The issuance of additional equity securities could have a dilutive effect on the value of our common shares, and may not be possible on terms acceptable to us given the current volatility in the financial markets. The issuance of additional debt would likely require that a portion of our cash flow from operations be used for the payment of interest on our debt, thereby reducing our ability to use our cash flow to fund working capital, capital expenditures, acquisitions, dividends and general corporate requirements, which could place us at a competitive disadvantage relative to other competitors. Our cash flow from operations and access to capital is subject to a number of variables, including:

- our estimated proved reserves;
- the level of natural gas we are able to produce from existing wells;
- our ability to extract natural gas liquids from the natural gas we produce;
- the prices at which natural gas liquids and natural gas are sold; and
- our ability to acquire, locate and produce new reserves.

If our revenues decrease as a result of lower natural gas prices, operating difficulties or declines in reserves, our ability to obtain the capital necessary to undertake or complete future exploration and development programs and to pursue other opportunities may be limited, which could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could result in a decline in our oil and natural gas reserves.

We pursue acquisitions as part of our growth strategy and there are risks associated with such acquisitions.

Our growth has been attributable in part to acquisitions of producing properties and companies. Recently we have been focused on acquiring acreage for our drilling program. We expect to continue to evaluate and, where appropriate, pursue acquisition opportunities on terms we consider favorable. However, we cannot assure you that suitable acquisition candidates will be identified in the future, or that we will be able to finance such acquisitions on favorable terms. In addition, we compete against other companies for acquisitions, and we cannot assure you that we will successfully acquire any material property interests. Further, we cannot assure you that future acquisitions by us will be integrated successfully into our operations or will increase our profits.

The successful acquisition of producing properties requires an assessment of numerous factors beyond our control, including, without limitation:

- recoverable reserves;
- exploration potential;
- future natural gas prices;
- operating costs; and
- potential environmental and other liabilities.

In connection with such assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. The resulting assessments are inexact and their accuracy uncertain, and such a review may not reveal all existing or potential problems, nor will it necessarily permit us to become sufficiently familiar with the properties to fully assess their merits and deficiencies. Inspections may not always be performed on every well, and structural and environmental problems are not necessarily observable even when an inspection is made.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties, which may be substantially different in operating and geologic characteristics or geographic location than our existing properties. While our current operations are focused in Texas and Louisiana, we may pursue acquisitions or properties located in other geographic areas.

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

Market conditions or the unavailability of satisfactory natural gas transportation arrangements may hinder our access to natural gas markets or delay our production. The availability of a ready market for our natural gas production depends on a number of factors, including the demand for and supply of natural gas and the proximity of reserves to pipelines and processing facilities. Our ability to market our production depends in a substantial part on the availability and capacity of gathering systems, pipelines and processing facilities, which, in some cases, may be owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells due to a lack of market demand or because of the inadequacy or unavailability of pipelines or gathering system capacity. If that were to occur, then we would be unable to realize revenue from those wells until arrangements were made to deliver our production to market.

Our debt service requirements could adversely affect our operations and limit our growth.

We had $2.7 billion principal amount of debt as of December 31, 2021.

Our outstanding debt has important consequences, including, without limitation:

- a portion of our cash flow from operations is required to make debt service payments;
- our ability to borrow additional amounts for capital expenditures (including acquisitions) or other purposes is limited; and
- our debt limits (i) our ability to capitalize on significant business opportunities, (ii) our flexibility in planning for or reacting to changes in market conditions, and (iii) our ability to withstand competitive pressures and economic downturns.

Future acquisitions or development activities may require us to alter our capitalization significantly. These changes in capitalization may significantly increase our debt. Moreover, our ability to meet our debt service obligations and to reduce our total debt will be dependent upon our future performance, which will be subject to general economic conditions and financial, business and other factors affecting our operations, many of which are beyond our control. If we are unable to service our indebtedness and to meet other commitments, we will be required to adopt one or more alternatives, such as refinancing or restructuring our indebtedness, selling material assets or seeking to raise additional debt or equity capital. We cannot assure you that any of these actions could be effected on a timely basis or on satisfactory terms or that these actions would enable us to continue to satisfy our capital requirements.

Our debt agreements contain a number of significant covenants. These covenants limit our ability to, among other things:

- borrow additional money;
- merge, consolidate or dispose of assets;
- make certain types of investments;
- enter into transactions with our affiliates; and
- pay dividends.

Our failure to comply with any of these covenants could cause a default under our bank credit facility and the indentures governing our outstanding notes. A default, if not waived, could result in acceleration of our indebtedness, in which case the debt would become immediately due and payable. If this occurs, we may not be able to repay our debt or borrow sufficient funds to refinance it given the current status of the credit markets. Even if new financing is available, it may not be on terms that are acceptable to us.

Complying with these covenants may cause us to take actions that we otherwise would not take or not take actions that we otherwise would take.

Prospects that we decide to drill may not yield natural gas in commercially viable quantities or quantities sufficient to meet our targeted rate of return and firm transportation commitments.

A prospect is a property in which we own an interest, or have operating rights to, and that has what our geoscientists believe, based on available seismic and geological information, to be an indication of potential oil or natural gas. Our prospects are in various stages of evaluation, ranging from a prospect that is ready to be drilled to a prospect that will require substantial additional evaluation and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. The analysis that we perform using data from other wells, more fully explored prospects and/or producing fields may not be useful in predicting the characteristics and potential reserves associated with our drilling prospects. If we drill additional unsuccessful wells, our drilling success rate may decline and we may not achieve our targeted rate of return. Further, unsuccessful drilling may impact our ability to fulfill our firm transportation commitments.

Our business involves many uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses.

Our success depends on the success of our exploration and development activities. Exploration activities involve numerous risks, including the risk that no commercially productive natural gas reserves will be discovered. In addition, these activities may be unsuccessful for many reasons, including weather, cost overruns, equipment shortages and mechanical difficulties. Moreover, the successful drilling of a natural gas well does not ensure we will realize a profit on our investment. A variety of factors, both geological and market-related, can cause a well to become uneconomical or only marginally economical. In addition to their costs, unsuccessful wells can hurt our efforts to replace production and reserves.

Our business involves a variety of operating risks, including:

- unusual or unexpected geological formations;
- fires;
- explosions;
- blow-outs and surface cratering;
- uncontrollable flows of natural gas and formation water;
- natural disasters, such as hurricanes, tropical storms and other adverse weather conditions;
- pipe, cement, or pipeline failures;
- casing collapses;
- mechanical difficulties, such as lost or stuck oil field drilling and service tools;
- abnormally pressured formations; and
- environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases.

If we experience any of the above operating risks, our well bores, gathering systems and processing facilities could be affected, which could adversely affect our ability to conduct operations.

We could also incur substantial losses as a result of:

- injury or loss of life;
- severe damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- clean-up responsibilities;
- regulatory investigation and penalties;
- suspension of our operations; and
- repairs to resume operations.

We maintain insurance against "sudden and accidental" occurrences, which may cover some, but not all, of the risks described above. Most significantly, the insurance we maintain will not cover the risks described above which occur over a sustained period of time. Further, there can be no assurance that such insurance will continue to be available to cover all such cost or that such insurance will be available at a cost that would justify its purchase. The occurrence of a significant event not fully insured or indemnified against could have a material adverse effect on our financial condition and results of operations.

Loss of our information and computer systems could adversely affect our business.

We are heavily dependent on our information systems and computer-based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of these programs or systems were to fail or create erroneous information in our hardware or software network infrastructure, possible consequences include loss of our communication links, our inability to find, produce, process and sell oil and natural gas and the inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any of these consequences could have a material effect on our business.

Our business could be negatively impacted by security threats, including cyber-security threats and other disruptions.

As an oil and natural gas producer, we face various security threats, including cyber-security threats to gain unauthorized access to sensitive information or to render data or systems unusable, threats to the safety of our employees, threats to the security or operation of our facilities and infrastructure or third party facilities and infrastructure, such as processing plants and pipelines, and threats from terrorist acts. Cyber-security attacks in particular are evolving and include, but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. Although we utilize various procedures and controls to monitor and protect against these threats and to mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. If any of these events were to materialize, either to the Company or a third party upon which we rely, they could lead to losses of sensitive information, critical infrastructure, personnel or capabilities, essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations, or cash flows.

We are subject to extensive governmental laws and regulations that may adversely affect the cost, manner or feasibility of doing business.

Our operations and facilities are subject to extensive federal, state and local laws and regulations relating to the exploration for, and the development, production and transportation of, oil and natural gas, as well as the safe operations thereof. Future laws or regulations, adverse changes in the interpretation of existing laws and regulations or our failure to comply with existing legal requirements may harm our business, results of operations and financial condition. We may be required to make large and unanticipated capital expenditures to comply with present and future governmental laws and regulations, such as:

- lease permit restrictions;
- drilling bonds and other financial responsibility requirements, such as plug and abandonment bonds;
- spacing of wells;
- unitization and pooling of properties;
- safety precautions;
- regulatory requirements; and
- taxation.

Under these laws and regulations, we could be liable for:

- personal injuries;
- property and natural resource damages;
- well reclamation costs; and
- governmental sanctions, such as fines and penalties.

Our operations could be significantly delayed or curtailed and our cost of operations could significantly increase as a result of regulatory requirements or restrictions. In addition, the Biden administration has made, and is expected to make additional changes to applicable regulations, and in each case we expect changes to be more stringent than those of the prior administration. There are also costs associated with responding to changing regulations and policies, whether such regulations are more or less stringent. As such, there can be no assurance that material cost and liabilities will not be incurred in the future.

The widespread outbreak of an illness, pandemic or any other public health crisis may have material adverse effects on our business, financial position, results of operations and/or cash flows.

In December 2019, a novel strain of coronavirus (SARS-CoV-2), which causes COVID-19, was reported to have surfaced in China. The spread of this virus caused business disruption beginning in January 2020, including disruption to the oil and natural gas industry. In March 2020, the World Health Organization declared the outbreak of COVID-19 to be a pandemic, and the U.S. economy began to experience pronounced effects. The COVID-19 pandemic has negatively impacted the global economy, disrupted global supply chains, reduced global demand for oil and natural gas, and created significant volatility and disruption of financial and commodity markets. The extent of the impact of the COVID-19 pandemic on our operational and financial performance, including our ability to execute our business strategies and initiatives in the expected time frame, is uncertain and depends on various factors, including the demand for oil and natural gas, the availability of personnel, equipment and services critical to our ability to operate our properties and the impact of potential governmental restrictions on travel, transports and operations. There is uncertainty around the extent and duration of the disruption. The degree to which the COVID-19 pandemic or any other public health crisis adversely impacts our results will depend on future developments, which are highly uncertain and cannot be predicted, including, but not limited to, the duration and spread of the outbreak, its severity, the actions to contain the virus or treat its impact, its impact on the economy and market conditions, and how quickly and to what extent normal economic and operating conditions can resume. In 2021, the pandemic did not significantly disrupt our operations apart from the impact it had on oil and natural gas prices.

ITEM 1B. *UNRESOLVED STAFF COMMENTS*

None.

ITEM 3. *LEGAL PROCEEDINGS*

We are not a party to any legal proceedings which management believes will have a material adverse effect on our consolidated results of operations or financial condition.

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*

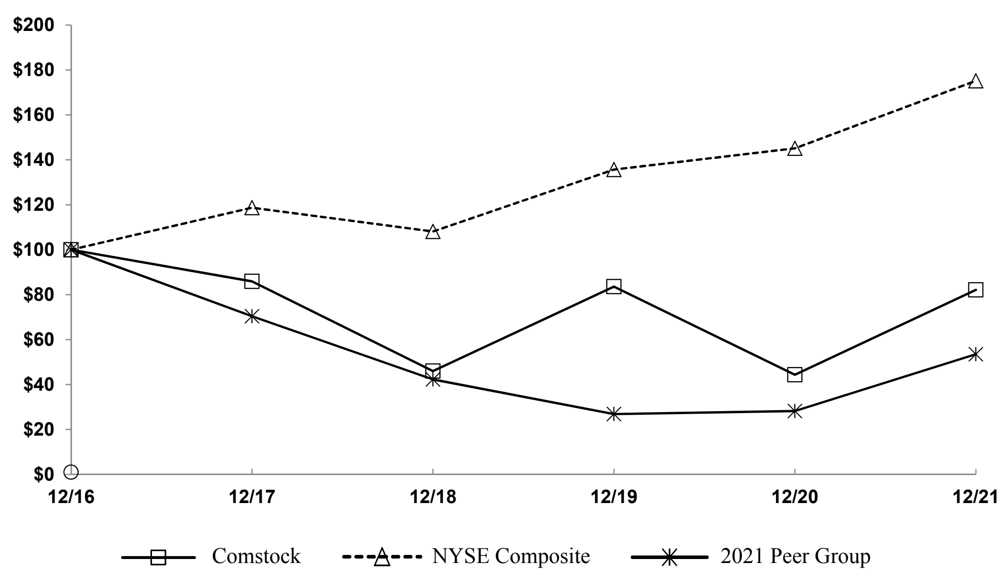
Our common stock is listed for trading on the New York Stock Exchange under the symbol "CRK". As of February 16, 2022, we had 232,922,620 shares of common stock outstanding, which were held by 100 holders of record. We have not paid a dividend on our common stock since 2014. Any future determination as to the payment of dividends will depend upon the results of our operations, capital requirements, our financial condition and such other factors as our board of directors may deem relevant.

Stockholder Return Performance

A peer group of companies is used by our compensation committee to determine total stockholder return performance which is used as a metric in our Annual Incentive Plan and to determine whether performance share units are earned as awarded under our 2019 Long-term Incentive Plan. In 2021, the compensation committee utilized a peer group that consisted of Antero Resources Corporation, Chesapeake Energy Corporation, Coterra Energy Inc., CNX Resources Corporation, EQT Corporation, Vine Energy Inc., SPDR S&P Oil and Gas Exploration & Production ETF, Range Resources, Inc., SilverBow Resources, Inc. and Southwestern Energy Company. The following graph compares the yearly percentage change in the cumulative total stockholder return on our common stock during the five years ended December 31, 2021 with the cumulative return on the New York Stock Exchange Index and the cumulative return for our 2021 peer group. The graph assumes that $100.00 was invested on the last trading day of 2015, and that dividends, if any, were reinvested.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN [(1)]
Among Comstock, the NYSE Composite Index, and Our Peer Group

	As of December 31,					
Total Return Analysis	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Comstock	$100.00	$85.89	$45.99	$83.55	$44.37	$82.13
NYSE Composite	$100.00	$118.73	$108.10	$135.68	$145.16	$175.18
2021 Peer Group	$100.00	$70.42	$42.30	$26.86	$28.22	$53.51



(1) The data contained in the above graph is deemed to be furnished and not filed pursuant to Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liabilities of that section.

ITEM 7. ***MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS***

The following discussion and analysis should be read in conjunction with our selected historical consolidated financial data and our accompanying consolidated financial statements and the notes to those financial statements included elsewhere in this report. The following discussion includes forward-looking statements that reflect our plans, estimates and beliefs. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, those discussed below and elsewhere in this report, particularly in "Risk Factors" and "Cautionary Note Regarding Forward-Looking Statements."

Overview

We are an independent energy company engaged in the acquisition, exploration, development and production of oil and natural gas in the United States. Our assets are concentrated in the Haynesville and Bossier shale located in North Louisiana and East Texas, a premier natural gas basin with superior economics due to the geographic proximity to Gulf Coast natural gas markets. We own interests in 2,557 producing oil and natural gas wells (1,459.6 net) and we operate 1,575 of these wells. We intend to maintain an operating plan in 2022 targeting additional debt reduction and generation of free cash flow.

We use the successful efforts method of accounting, which allows only for the capitalization of costs associated with developing proven oil and natural gas properties as well as exploration costs associated with successful exploration activities. Accordingly, our exploration costs consist of costs we incur to acquire seismic data, impairments of our unevaluated leasehold where we were not successful in discovering reserves and the costs of unsuccessful exploratory wells that we drill.

We generally sell our oil and natural gas at current market prices at the point our wells connect to third party purchaser pipelines or terminals. We have entered into certain transportation and treating agreements with midstream and pipeline companies to transport a substantial portion of our natural gas production to long-haul gas pipelines. We market our products several different ways depending upon a number of factors, including the availability of purchasers for the product, the availability and cost of pipelines near our wells, market prices, pipeline constraints and operational flexibility. Accordingly, our revenues are heavily dependent upon the prices of, and demand for, oil and natural gas. Oil and natural gas prices have historically been volatile and are likely to remain volatile in the future.

Our operating costs are generally comprised of several components, including costs of our field personnel, insurance, repair and maintenance costs, production supplies, fuel used in operations, transportation costs, workover expenses and state production and ad valorem taxes.

Like all oil and natural gas exploration and production companies, we face the challenge of replacing our reserves. Although in the past we have offset the effect of declining production rates from existing properties through successful acquisition and drilling efforts, there can be no assurance that we will be able to continue to offset production declines or maintain production at current rates through future acquisitions or drilling activity.

Our operations and facilities are subject to extensive federal, state and local laws and regulations relating to the exploration for, and the development, production and transportation of, oil and natural gas, and operating safety. Future laws or regulations, any adverse changes in the interpretation of existing laws and regulations or our failure to comply with existing legal requirements may have an adverse effect on our business, results of operations and financial condition. Applicable environmental regulations require us to remove our equipment after production has ceased, to plug and abandon our wells and to remediate any environmental damage our operations may have caused. The present value of the estimated future costs to plug and abandon our oil and gas wells and to dismantle and remove our production facilities is included in our reserve for future abandonment costs, which was $25.7 million as of December 31, 2021.

Prices for oil and natural gas have been highly volatile in recent years but we expect our natural gas production to increase, assuming we maintain a sufficient development program to offset expected production declines from our producing wells. The level of our drilling activity is dependent on natural gas prices. If we are unable to offset production declines resulting from the new wells we plan to drill in 2022 and future periods, our production volumes and cash flows from our operating activities may not be sufficient to fund our capital expenditures, and thus, we may need to either curtail drilling activity or seek additional borrowings, which would result in an increase in our interest expense in 2022 and future periods. We may need to recognize impairments if oil and natural gas prices decline, and as a result, the expected future cash flows from these properties becomes insufficient to recover their carrying value.

Results of Operations

Year Ended December 31, 2021 Compared to Year Ended December 31, 2020

Our operating data for the year ended December 31, 2021 and 2020 are summarized below:

	Year Ended December 31,	
	2021	2020
Oil and Gas Sales ***(in thousands)*****:**		
Natural gas	$1,775,768	$809,399
Oil	74,962	48,796
Total oil and gas sales	$1,850,730	$858,195
Net Production Data:		
Natural gas (MMcf)	489,274	450,836
Oil (MBbls)	1,210	1,508
Total oil and gas (MMcfe)	496,534	459,883
Average Sales Price:		
Natural gas ($/Mcf)	$3.63	$1.80
Oil ($/Bbl)	$61.95	$32.36
Total oil and gas sales ($/Mcfe)	$3.73	$1.87
Expenses ($ per Mcfe):		
Production and ad valorem taxes	$0.10	$0.08
Gathering and transportation	$0.26	$0.23
Lease operating	$0.21	$0.22
Depreciation, depletion and amortization	$0.95	$0.91

Oil and gas sales. Oil and gas sales of $1.9 billion in 2021 increased $992.5 million or 116% over oil and gas sales in 2020 of $858.2 million. The increase is due to a 9% increase in our natural gas production along with a 99% increase in realized oil and natural gas prices in 2021. Our 2021 natural gas production was 489.3 billion cubic feet ("Bcf") (1.3 Bcf per day), which was sold at an average price of $3.63 per Mcf as compared to 450.8 Bcf (1.2 Bcf per day) sold at an average price of $1.80 in 2020. Our 2021 oil production was 1.2 MMBbls (3,315 Bbls per day), which was sold at an average price of $61.95 per Bbl as compared to 1.5 MMBbls (4,120 Bbls per day) sold at an average price of $32.36 per Bbl in 2020.

We utilize natural gas and oil price derivative financial instruments to manage our exposure to changes in natural gas and oil prices and protect returns on investment from our drilling activities. The following table presents our natural gas and oil prices before and after the effect of cash settlements of our derivative financial instruments:

	Year Ended December 31,	
	2021	2020
Average Realized Natural Gas Price:		
Natural gas, per Mcf	$ 3.63	$ 1.80
Cash settlements on derivative financial instruments, per Mcf	(0.84)	0.27
Price per Mcf, including cash settlements on derivative financial instruments	$ 2.79	$ 2.07
Average Realized Oil Price:		
Crude oil per Barrel	$ 61.95	$ 32.36
Cash settlements on derivative financial instruments, per Barrel	(6.67)	8.52
Price per Barrel, including cash settlements on derivative financial instruments	$ 55.28	$ 40.88

Production and ad valorem taxes. Our production and ad valorem taxes increased $12.2 million (33%) to $49.1 million in 2021 from $37.0 million in 2020. This increase is primarily related to the increase in oil and natural gas sales in 2021.

Gathering and transportation. Gathering and transportation costs increased $24.4 million or 23% to $130.9 million in 2021 as compared to $106.6 million in 2020. This increase was due primarily to the higher natural gas production in 2021 combined with a higher average rate.

Lease operating expenses. Our lease operating expense of $103.5 million in 2021 was $1.0 million or 1% higher than the lease operating expenses in 2020 of $102.5 million due to the higher natural gas production. Our lease operating expense of $0.21 per Mcfe produced for 2021 was comparable to the 2020 rate of $0.22 per Mcfe.

Depreciation, depletion and amortization expense ("DD&A"). DD&A increased $52.3 million (13%) to $469.4 million in 2021 from $417.1 million in 2020 and our DD&A per equivalent Mcf produced was $0.95 per Mcfe in 2021 as compared to $0.91 per Mcfe in 2020. The increase in DD&A is primarily due to the 9% increase in natural gas production.

General and administrative expenses. General and administrative expense, which is reported net of overhead reimbursements, increased to $34.9 million in 2021 from $32.0 million in 2020 due primarily to higher personnel costs. Stock-based compensation was $6.8 million and $6.5 million in 2021 and 2020, respectively.

Loss on sale of assets. We reported a loss on the sale of assets of $162.1 million for 2021 which was primarily related to our divestiture of our Bakken shale assets. In November 2021, we divested our assets in the Bakken shale for net proceeds of $138.1 million in cash.

Derivative financial instruments. We use derivative financial instruments as part of our price risk management program to protect our capital investments. We had net losses on derivative financial instruments of $560.6 million for 2021 as compared to net gains of $10.0 million for 2020. Realized net losses from our oil and natural gas price risk management program were $419.9 million in 2021 as compared to realized net gains of $134.9 million in 2020. Realized gains from our interest rate risk management program were $163 thousand in 2021 as compared to realized losses of $389 thousand in 2020. Unrealized losses on derivative financial instruments were $140.9 million in 2021 and $124.5 million in 2020.

Interest expense. Interest expense was $218.5 million for 2021 as compared to $234.8 million for 2020. Included in interest expense was amortization of the discount on our senior notes and the debt cost amortization associated with our outstanding debt. The non-cash interest expense for 2021 totaled $21.7 million compared with non-cash interest expense of $34.0 million for 2020. The decrease in interest expense for 2021 is due primarily to the retirement of our 9.75% and 7.50% senior notes during 2021.

Loss on early retirement of debt. We repurchased $375.0 million principal amount of our 7.50% senior notes and $1.65 billion principal amount of our 9.75% senior notes in 2021. As a result of premiums paid over face value and costs associated with the repurchases, we recognized a loss on early retirement of debt of $352.6 million during 2021. During 2020, we exchanged 767,096 shares of our common stock to retire $5.6 million aggregate principal amount of our 7.50% senior notes and recognized a $861 thousand loss on early retirement of debt.

Income taxes. Income taxes were a provision of $11.4 million in 2021 and a benefit of $9.2 million in 2020. The effective tax rate of -5% in 2021 and 15% in 2020 differed from the federal income tax rate of 21% primarily due to the impact of an increase to our valuation allowance on our federal and state net operating loss carryforwards and due to higher state current taxes.

Net income. We reported a net loss available to common stockholders of $259.2 million or $1.12 per diluted share in 2021 and net loss available to common stockholders of $83.4 million or $0.39 per diluted share in 2020. The net loss in 2021 is primarily due to losses on derivative financial instruments of $560.6 million, the loss on early retirement of debt of $352.6 million and the $162.2 million loss on the Bakken shale divestiture. Income from operations in 2021 was $900.8 million.

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019

Discussions of 2020 items and year-to-year comparisons between 2020 and 2019 that are not included in this Annual Report on Form 10-K can be found in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2020 filed with the SEC on February 17, 2021.

Cash Flows, Liquidity and Capital Resources

Cash Flows

The following table summarizes sources and uses of cash and cash equivalents:

	Year Ended December 31, 2021	Year Ended December 31, 2020
	(in thousands)	
Sources of cash and cash equivalents:		
Operating activities	$ 859,005	$ 575,701
Issuance of new senior notes	2,186,896	737,129
Proceeds from asset sales	138,394	287
Issuance of common stock	—	196,380
Total	$ 3,184,295	$ 1,509,497
Uses of cash and cash equivalents:		
Retirement of senior notes	$ (2,210,626)	$ —
Capital expenditures	(689,210)	(509,690)
Repayments on bank credit facility, net of borrowings	(265,000)	(750,000)
Redemption of Series A convertible preferred stock	—	(210,000)
Preferred stock dividends	(17,500)	(25,580)
Other	(1,568)	(2,487)
Total	$ (3,183,904)	$ (1,497,757)

Cash flows from operating activities. Net cash provided by our operating activities increased $283.3 million (49%) to $859.0 million in 2021 from $575.7 million in 2020. The increase is primarily due to the 9% increase in our natural gas production and improved oil and natural gas prices in 2021.

Proceeds from asset sales. In 2021, we sold our non-operated properties in the Bakken shale and certain other properties for $138.4 million after selling expenses. The Bakken shale properties sold included non-operated interests in 442 producing wells (68.3 net) producing approximately 4,500 barrels of oil equivalent per day.

Issuance of common stock. In 2020, we sold 41,325,000 shares of common stock in an unwritten public offering and used the net proceeds of $196.4 million to substantially fund the redemption of our Series A convertible preferred stock for $210.0 million.

Issuance of new senior notes and retirement of senior notes. In March and June 2021, we issued $1.25 billion and $965.0 million principal amount of 6.75% senior notes due 2029 (the "2029 Notes") and 5.875% senior notes due 2030 (the "2030 notes"), respectively, in private placement offerings. The 2029 Notes mature on March 1, 2029 and accrue interest at a rate of 6.75% per annum, payable semi-annually on March 1 and September 1 of each year. The 2030 Notes mature on January 15, 2030 and accrue interest at a rate of 5.875% per annum, payable semi-annually on January 15 and July 15 of each year. The proceeds from the offerings were used to repurchase $375.0 million principal amount of our 7.5% senior notes due 2025 and to repurchase $1.65 billion principal amount of our 9.75% senior notes due 2026. The redemption of the senior notes included $171.9 million in premiums paid over face value, accrued interest of $44.2 million and $1.1 million of costs related to the offerings. In 2020, we issued $800.0 million principal amount of our 9.75% Senior Notes due 2026 in an underwritten public offering and received net proceeds of $737.1 million. The proceeds were used to reduce amounts outstanding under our bank credit facility.

Capital expenditures. The increase in capital expenditures of $179.5 million is primarily due to higher drilling, completion and acquisition activities in 2021. We spent $57.7 million in 2021 to acquire approximately 49,000 net undeveloped acres prospective for the Haynesville and Bossier shale through acquisitions or direct leasing. In 2020, we acquired 13,519 net acres for $7.9 million.

Our capital expenditures are summarized in the following table:

	Year Ended December 31, 2021	2020
	(in thousands)	
Acquisitions:		
Proved property	$ 21,781	$ —
Unproved property	35,871	7,949
Exploration and development:		
Development leasehold costs	12,953	13,022
Exploratory drilling and completion costs	6,966	—
Development drilling and completion costs	569,141	436,074
Other development costs	39,168	34,572
Change to asset retirement obligations	5,608	(47)
Total exploration and development	691,488	491,570
Other	192	400
Total capital expenditures	$ 691,680	$ 491,970
Change in accrued capital expenditures and other	3,138	17,673
Change in asset retirement obligations	(5,608)	47
Total cash capital expenditures	$ 689,210	$ 509,690

We currently expect to spend approximately $750 million to $800 million in 2022 on our development and exploration projects primarily focused on the continued development of our Haynesville/Bossier shale properties, which includes $60 million to $65 million on infrastructure, workovers and other development costs. Under our current operating plan, we expect to drill 67 operated horizontal wells (52.1 net) and to turn 69 wells (56.0 net) to sales in 2022. The Company also expects to spend an additional $8 million to $12 million on leasing activities in 2022.

Liquidity and Capital Resources

As of December 31, 2021, we had $1.2 billion of liquidity, comprised of $1.17 billion of unused borrowing capacity under our bank credit facility and $30.7 million of cash and cash equivalents on hand. Our short and long-term capital requirements consist primarily of funding our development and exploration activities, acquisitions, payments of contractual obligations, and debt service.

We expect to fund our future development and exploration activities with future operating cash flow. The timing of most of our capital expenditures is discretionary because we have no material long-term capital expenditure commitments. Consequently, we have a significant degree of flexibility to adjust the level of our capital expenditures as circumstances warrant. If our plans or assumptions change or prove to be inaccurate, we may be required to seek additional capital, including debt or equity financing. We expect to fund future acquisitions, depending on the size and timing, with future operating cash flow, borrowings under our bank credit facility, or other debt or equity financings, to the extent available. The availability and attractiveness of debt or equity financing will depend upon a number of factors, some of which will relate to our financial condition and performance and some of which will be beyond our control, such as prevailing interest rates, oil and natural gas prices and other market conditions. We cannot provide any assurance that we will be able to obtain such capital, or if such capital is available, that we will be able to obtain it on acceptable terms.

Our contractual obligations consist primarily of natural gas transportation and gathering contracts and drilling and completion contracts. Our natural gas transportation and gathering contracts extend to 2031 and commitments under these contracts are $41.2 million for 2022, $41.5 million for 2023, $41.6 million for 2024, $29.8 million for 2025, $25.0 million for 2026 and $24.8 million for 2027 through 2030. Terms of drilling contracts vary from well to well, or are for periods of less than one year. Existing commitments under drilling contracts is $12.3 million for 2022. In 2021, the Company entered into a well stimulation agreement that extends to 2024 for exclusive use of a natural gas powered pressure pumping fleet. The minimum commitment under this contract is $19.2 million per year from 2022 through 2024.

As of December 31, 2021, we had $235.0 million outstanding under our bank credit facility that matures on July 16, 2024. The borrowing base, which is currently set at $1.4 billion, is re-determined on a semi-annual basis and upon the occurrence of certain other events. Borrowings under the bank credit facility are secured by substantially all of our assets and those of our subsidiaries and bear interest at our option, at either LIBOR plus 2.25% to 3.25% or a base rate plus 1.25% to 2.25%, in each case depending on the utilization of the borrowing base. We also pay a commitment fee of 0.375% to 0.5% on the unused portion of the borrowing base. The bank credit facility places certain restrictions upon our and our subsidiaries' ability to, among other things, incur additional indebtedness, pay cash dividends, repurchase common stock, make certain loans, investments and divestitures and redeem the senior notes. The only financial covenants are the maintenance of a leverage ratio of less than 4.0 to 1.0 and an adjusted current ratio of at least 1.0 to 1.0. We were in compliance with the covenants as of December 31, 2021.

Federal and State Taxation

At December 31, 2021, we had $906.6 million in U.S. federal net operating loss carryforwards and $1.5 billion in certain state net operating loss carryforwards. As a result of a change of control in August 2018, our ability to use U.S. federal net operating losses ("NOLs") to reduce taxable income is generally limited to an annual amount based on the fair market value of our stock immediately prior to the ownership change multiplied by the long-term tax-exempt interest rate. Our NOLs are estimated to be limited to $3.3 million a year as a result of this limitation. In addition to this limitation, IRC Section 382 provides that a corporation with a net unrealized built-in gain immediately before an ownership change may increase its limitation by the amount of built-in gain recognized during a recognition period, which is generally the five-year period immediately following an ownership change. Based on the fair market value of our common stock immediately prior to the ownership change, we believe that we have a net unrealized built-in gain which will increase the Section 382 limitation during the five-year recognition period from 2018 to 2023 by $117.0 million.

NOLs that exceed the Section 382 limitation in any year continue to be allowed as carryforwards until they expire and can be used to offset taxable income for years within the carryover period subject to the limitation in each year. NOLs incurred prior to 2018 generally have a 20-year life until they expire. NOLs generated in 2018 and after would be carried forward indefinitely. Our use of new NOLs arising after the date of an ownership change would not be affected by the 382 limitation. If we do not generate a sufficient level of taxable income prior to the expiration of the pre-2018 NOL carry-forward periods, then we will lose the ability to apply those NOLs as offsets to future taxable income. We estimate that $834.6 million of the U.S. federal NOL carryforwards and $1.3 billion of the estimated state NOL carryforwards will expire unused.

Our federal income tax returns for the years subsequent to December 31, 2017 remain subject to examination. Our income tax returns in major state income tax jurisdictions remain subject to examination for various periods subsequent to December 31, 2018. We currently believe that our significant filing positions are highly certain and that all of our other significant income tax filing positions and deductions would be sustained upon audit or the final resolution would not have a material effect on our consolidated financial statements. Therefore, we have not established any significant reserves for uncertain tax positions.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and use assumptions that can affect the reported amounts of assets, liabilities, revenues or expenses.

Successful efforts accounting. We are required to select among alternative acceptable accounting policies. There are two generally acceptable methods for accounting for oil and gas producing activities. The full cost method allows the capitalization of all costs associated with finding oil and natural gas reserves, including certain general and administrative expenses. The successful efforts method allows only for the capitalization of costs associated with developing proven oil and natural gas properties as well as exploration costs associated with successful exploration projects. Costs related to exploration that are not successful are expensed when it is determined that commercially productive oil and gas reserves were not found. We have elected to use the successful efforts method to account for our oil and gas activities and we do not capitalize any of our general and administrative expenses.

Oil and natural gas reserve quantities. The determination of depreciation, depletion and amortization expense is highly dependent on the estimates of the proved oil and natural gas reserves attributable to our properties. The determination of whether impairments should be recognized on our oil and gas properties is also dependent on these estimates, as well as estimates of probable reserves. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate depends on the quality of available data, production history and engineering and geological interpretation and judgment. Because all reserve estimates are to some degree imprecise, the quantities and timing of oil and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil and natural gas prices may all differ materially from those assumed in these estimates. Proved reserve estimates included in this report were prepared by the Company's engineers and audited by independent petroleum engineers.

The information regarding present value of the future net cash flows attributable to our proved oil and natural gas reserves are estimates only and should not be construed as the current market value of the estimated oil and natural gas reserves attributable to our properties. Thus, such information includes revisions of certain reserve estimates attributable to proved properties included in the preceding year's estimates. Such revisions reflect additional information from subsequent activities, production history of the properties involved and any adjustments in the projected economic life of such properties resulting from changes in product prices. Any future downward revisions could adversely affect our financial condition, our future prospects and the value of our common stock.

Impairment of oil and gas properties. We evaluate our proved properties for potential impairment when circumstances indicate that the carrying value of an asset may not be recoverable. If impairment is indicated based on a comparison of the asset's carrying value to its undiscounted expected future net cash flows, then it is recognized to the extent that the carrying value exceeds fair value. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Expected future cash flows are determined using estimated future prices based on market based forward prices applied to projected future production volumes. The projected production volumes are based on the property's proved and risk adjusted probable oil and natural gas reserves estimates at the end of the period. The estimated future cash flows that we use in our assessment of the need for an impairment are based on a corporate forecast which considers forecasts from multiple independent price forecasts. Prices are not escalated to levels that exceed observed historical market prices. Costs are also assumed to escalate at a rate that is based on our historical experience, currently estimated at 2% per annum. The oil and natural gas prices used for determining asset impairments will generally differ from those used in the standardized measure of discounted future net cash flows because the standardized measure requires the use of the average first day of the month historical price for the year. Unproved properties are evaluated for impairment based upon the results of drilling, planned future drilling and the terms of our oil and gas leases. It is reasonably possible that our estimates of undiscounted future net cash flows attributable to its oil and gas properties may change in the future. The primary factors that may affect estimates of future cash flows include future adjustments, both positive and negative, to proved and appropriate risk-adjusted probable oil and gas reserves, results of future drilling activities, future prices for oil and natural gas, and increases or decreases in production and capital costs. As a result of these changes, there may be impairments in the carrying values of our proved and unproved oil and gas properties in the future.

Goodwill. We have goodwill of $335.9 million as of December 31, 2021 that was recorded in 2018. Goodwill represents the excess of purchase price over fair value of net tangible and identifiable intangible assets. We are not required to amortize goodwill as a charge to earnings; however, we are required to conduct an annual review of goodwill for impairment. We determine the potential for impairment of our goodwill by initially preparing a qualitative fair value assessment of our business value. In performing this qualitative assessment, we examine relevant events and circumstances that could have a negative effect on our business, including macroeconomic conditions, industry and market conditions (including current commodity price), earnings and cash flows, overall financial performance and other relevant entity specific events.

If the qualitative assessment indicates that it is more likely than not that our business is impaired, a quantitative analysis would be performed to assess our fair value and to determine the amount of impairment, if any, that requires recognition. When performing a quantitative impairment assessment of goodwill, fair value is determined based on a market approach or an income approach. If the carrying value of goodwill exceeds the fair value calculated using the quantitative approach, an impairment charge would be recorded for the difference between fair value and carrying value. If oil or natural gas prices decrease, drilling efforts are unsuccessful or our market capitalization declines, it is reasonably possible that impairments would need to be recognized. We performed a quantitative assessment of goodwill as of October 1, 2021 and determined there was no goodwill impairment.

Income Taxes. We account for income taxes using the asset and liability method, whereby deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax basis, as well as the future tax consequences attributable to the future utilization of existing tax net operating loss and other types of carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that the change in rate is enacted.

In recording deferred income tax assets, we consider whether it is more likely than not that some portion or all of our deferred income tax assets will be realized in the future. The ultimate realization of deferred income tax assets is dependent upon the generation of future taxable income during the periods in which those deferred income tax assets would be deductible. We believe that after considering all the available objective evidence, historical and prospective, with greater weight given to historical evidence, we are not able to determine that it is more likely than not that all of our deferred tax assets will be realized. As a result, we established valuation allowances for our deferred tax assets and U.S. federal and state net operating loss carryforwards that are not expected to be utilized due to the uncertainty of generating taxable income prior to the expiration of the carryforward periods. We will continue to assess the valuation allowances against deferred tax assets considering all available information obtained in future reporting periods.

ITEM 7A. *QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK*

Our financial condition, results of operations and capital resources are highly dependent upon the prevailing market prices of natural gas and oil. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors, some of which are beyond our control. Factors influencing oil and natural gas prices include the level of global demand for oil, the foreign supply of natural gas and oil, the establishment of and compliance with production quotas by oil exporting countries, weather conditions that determine the demand for natural gas, the price and availability of alternative fuels and overall economic conditions. It is impossible to predict future natural gas and oil prices with any degree of certainty. Sustained weakness in natural gas and oil prices may adversely affect our financial condition and results of operations, and may also reduce the amount of natural gas and oil reserves that we can produce economically. Any reduction in our natural gas and oil reserves, including reductions due to price fluctuations, can have an adverse effect on our ability to obtain capital for our exploration and development activities. Similarly, any improvements in oil and natural gas prices can have a favorable impact on our financial condition, results of operations and capital resources.

As of December 31, 2021, we had natural gas price swap agreements to hedge approximately 121.3 Bcf of our 2022 through 2023 production at an average price of $2.67 per MMBtu. We have also entered into natural gas collars to hedge approximately 147.7 Bcf of our natural gas production with an average floor price of $2.63 per MMBtu and an average ceiling price of $3.92 per MMBtu. None of our derivative contracts have margin requirements or collateral provisions that could require funding prior to the scheduled cash settlement date.

An increase of 10% in the market price of natural gas on December 31, 2021 would decrease the fair value of our natural gas swaps and collars by approximately $64.0 million. A decrease of 10% in the market price of natural gas on December 31, 2021 would increase the fair value of our natural gas swaps and collars by approximately $61.4 million. The impact of hypothetical changes in market prices of natural gas on our natural gas derivative financial instruments does not include the offsetting impact that the same hypothetical changes in market prices of natural gas may have on our physical sales of natural gas. Since our outstanding natural gas derivative financial instruments hedge only a portion of our forecasted physical gas production, a positive or negative impact to the fair value of our natural gas derivative financial instruments would be partially offset by our physical sales of natural gas.

Interest Rates

At December 31, 2021, we had approximately $2.7 billion principal amount of long-term debt outstanding. $965.0 million of our long-term debt bear interest at a fixed rate of 5.875%, $1.25 billion of our long-term debt bear interest at a fixed rate of 6.75% and $244.4 million of our long-term debt bear interest at a fixed rate of 7.50%. The fair market value of the Senior Notes due 2030, Senior Notes due 2029 and Senior Notes due 2025 as of December 31, 2021 were $989.1 million, $1.3 billion and $248.1 million, respectively, based on the market price of approximately 102.5%, 107.0% and 101.5% of the face amount of such debt. At December 31, 2021, we had $235.0 million outstanding under our bank credit facility, which is subject to variable rates of interest that are tied to LIBOR or the corporate base rate, at our option. Any increase in these interest rates would have an adverse impact on our results of operations and cash flow.

ITEM 8. *FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA*

Our consolidated financial statements are included on pages F-1 to F-26 of this report.

We have prepared these financial statements in conformity with generally accepted accounting principles. We are responsible for the fairness and reliability of the financial statements and other financial data included in this report. In the preparation of the financial statements, it is necessary for us to make informed estimates and judgments based on currently available information on the effects of certain events and transactions.

Our registered independent public accountants, Ernst & Young LLP, are engaged to audit our financial statements and to express an opinion thereon. Their audit is conducted in accordance with auditing standards generally accepted in the United States to enable them to report whether the financial statements present fairly, in all material respects, our financial position and results of operations in accordance with accounting principles generally accepted in the United States.

The audit committee of our board of directors is comprised of three directors who are not our employees. This committee meets periodically with our independent public accountants and management. Our independent public accountants have full and free access to the audit committee to meet, with and without management being present, to discuss the results of their audits and the quality of our financial reporting.

ITEM 9. *CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE*

None.

ITEM 9A. *CONTROLS AND PROCEDURES*

Evaluation of Controls and Procedures. Disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended, or the Exchange Act) are designed to provide reasonable assurance that information required to be disclosed in reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures.

We performed an evaluation of the effectiveness of our disclosure controls and procedures as of December 31, 2021. The evaluation was performed with the participation of senior management of each business segment and key corporate functions, and under the supervision of the Chief Executive Officer and Chief Financial Officer.

Based on our evaluation of our disclosure controls and procedures, our chief executive officer and chief financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2021 to provide reasonable assurance that information required to be disclosed by us in the reports filed or submitted by us under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and to provide reasonable assurance that information required to be disclosed by us is accumulated and communicated to our management, including our chief executive officer and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting. There were no changes in our internal control over financial reporting during the quarter ended December 31, 2021 that materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting. We are responsible for establishing and maintaining adequate internal control over financial reporting for the Company. In order to evaluate the effectiveness of internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act, we conducted an assessment, including testing, using the criteria in Internal Control — Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Our system of internal control over financial reporting is 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. 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. As of December 31, 2021, we assessed the effectiveness of the Company's internal control over financial reporting based on the COSO criteria, and based on that assessment we determined that the Company maintained effective internal control over financial reporting as of December 31, 2021.

Ernst & Young LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting as of December 31, 2021. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting as of December 31, 2021, follows below.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Comstock Resources, Inc.

Opinion on Internal Control over Financial Reporting

We have audited Comstock Resources, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2021, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Comstock Resources, Inc. and subsidiaries (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2021 and 2020, the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2021, and the related notes and our report dated February 17, 2022 expressed an unqualified opinion thereon.

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. 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.

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/ ERNST & YOUNG LLP

Dallas, Texas
February 17, 2022

ITEM 9B. ***OTHER INFORMATION***

None.

PART III

ITEM 10. *DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE*

The information required by this item is incorporated herein by reference to "Business – Directors and Executive Officers" in this Form 10-K and to our definitive proxy statement which will be filed with the SEC within 120 days after December 31, 2021.

Section 16(a) Beneficial Ownership Reporting Compliance. Our directors, executive officers and stockholders with ownership of 10% or greater are required, under Section 16(a) of the Securities Exchange Act of 1934, to file reports of their ownership and changes to their ownership of our securities with the SEC. Based solely on our review of the reports and any written representations we received that no other reports were required, we believe that, during the year ended December 31, 2021, all of our officers, directors and stockholders with ownership of 10% or greater complied with all Section 16(a) filing requirements applicable to them.

Code of Ethics. We have adopted a Code of Business Conduct and Ethics that is applicable to all of our directors, officers and employees as required by New York Stock Exchange rules. We have also adopted a Code of Ethics for Senior Financial Officers that is applicable to our Chief Executive Officer and Senior Financial Officers. Both the Code of Business Conduct and Ethics and Code of Ethics for Senior Financial Officers may be found on our website at www.comstockresources.com. Both of these documents are also available, without charge, to any stockholder upon request to: Comstock Resources, Inc., Attn: Investor Relations, 5300 Town and Country Blvd., Suite 500, Frisco, Texas 75034, (972) 668-8800. We intend to disclose any amendments or waivers to these codes that apply to our Chief Executive Officer and senior financial officers on our website in accordance with applicable SEC rules. Please see the definitive proxy statement for our 2021 annual meeting, which will be filed with the SEC within 120 days of December 31, 2021, for additional information regarding our corporate governance policies.

ITEM 11. *EXECUTIVE COMPENSATION*

The information required by this item is incorporated herein by reference to our definitive proxy statement which will be filed with the SEC within 120 days after December 31, 2021.

ITEM 12. *SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS*

The following table summarizes certain information regarding our equity compensation plans as of December 31, 2021:

	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Number of securities authorized for future issuance under equity compensation plans (excluding outstanding options, warrants and rights)
Equity compensation plans approved by stockholders	2,099,820 [(1)]	4,439,784

(1) Represents performance share unit awards that would be issuable based upon achievement of the maximum awards under the terms of the performance share unit awards.

We do not have any equity compensation plans that were not approved by stockholders.

Further information required by this item is incorporated herein by reference to our definitive proxy statement which will be filed with the SEC within 120 days after December 31, 2021.

ITEM 13. *CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE*

The information required by this item is incorporated herein by reference to our definitive proxy statement which will be filed with the SEC within 120 days after December 31, 2021.

ITEM 14. *PRINCIPAL ACCOUNTANT FEES AND SERVICES*

The information required by this item is incorporated herein by reference to our definitive proxy statement which will be filed with the SEC within 120 days after December 31, 2021.

PART IV

ITEM 15. *EXHIBITS AND FINANCIAL STATEMENT SCHEDULES*

(a) Financial Statements:

1. The following consolidated financial statements and notes of Comstock Resources, Inc. are included on Pages F-2 to F-26 of this report:

2. All financial statement schedules are omitted because they are not applicable, or are immaterial or the required information is presented in the consolidated financial statements or the related notes.

(b) Exhibits:

The exhibits to this report required to be filed pursuant to Item 15(c) are listed below.

Exhibit No.	Description
2.1	Contribution Agreement dated May 9, 2018, by and among Arkoma Drilling, L.P., Williston Drilling, L.P. and the Company (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K/A dated May 9, 2018).
2.2	Amendment No. 1 to the Contribution Agreement, dated as of August 14, 2018, by and among Arkoma Drilling, L.P., Williston Drilling, L.P. and the Company (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K dated August 13, 2018).
2.3	Agreement and Plan of Merger, dated June 7, 2019, by and among the Company, Covey Park Energy LLC, New Covey Park Energy LLC and Covey Park Energy Holdings LLC (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K dated June 7, 2019).
2.4	First Amendment to Agreement and Plan of Merger dated as of July 15, 2019 by and among the Company, New Covey Park Energy LLC, Covey Park Energy LLC and Covey Park Energy Holdings LLC (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated July 15, 2019).
3.1	Second Amended and Restated Articles of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated August 13, 2018).
3.2	Amendment to Second Amended and Restated Articles of Incorporation of the Company, dated July 16, 2019 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated July 15, 2019).
3.3	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated August 21, 2014).
3.4	First Amendment to Amended and Restated Bylaws of the Company (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated August 17, 2018).
3.5	Amendment No. 2 to the Amended and Restated Bylaws (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K dated July 15, 2019).
4.1	Indenture dated May 3, 2017 between Covey Park Energy LLC, Covey Park Finance Corp. and Wells Fargo Bank National Association, as Trustee, for the 7.50% Senior Notes due 2025 (incorporated by reference to Exhibit 4.7 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2019).
4.2	Supplemental Indenture dated July 16, 2019 among the Company and Wells Fargo Bank, National Association for the 7.50% Senior Notes due 2025 (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated July 15, 2019).
4.3	Supplemental Indenture dated July 16, 2019 among the Company, the Guaranteeing Subsidiaries and Wells Fargo Bank, National Association for the 7.50% Senior Notes due 2025 (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K dated July 15, 2019).
4.4	Instrument of Resignation, Appointment and Acceptance dated as of July 16, 2019 among the Company, the Subsidiary Guarantors named therein, Wells Fargo Bank, N.A. and American Stock Transfer & Trust Company LLC (incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K dated July 15, 2019).
4.5	Indenture dated March 4, 2021, by and among the Company, each of the guarantor subsidiaries named therein, and American Stock Transfer & Trust Company, LLC for the 6.75% Senior Notes due 2029 (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated March 4, 2021).

Exhibit No.	Description
4.6	Indenture dated June 28, 2021, by and among the Company, each of the guarantor subsidiaries named therein, and American Stock Transfer & Trust Company, LLC for the 5.875% Senior Notes due 2030 (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated June 28, 2021).
4.7	Certificate of Designations of the Series B Redeemable Convertible Preferred Stock (incorporated by reference to Exhibit 4.4 to our Current Report on Form 8-K dated July 15, 2019).
4.8	Shareholders Agreement, dated June 7, 2019, by and among the Company, Arkoma Drilling CP, LLC, Williston Drilling CP, LLC, Arkoma Drilling, L.P., Williston Drilling, L.P., New Covey Park Energy LLC and Jerral W. Jones (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated June 10, 2019).
4.9*	Description of Securities.
10.1	Amended and Restated Credit Agreement dated as of July 16, 2019, among the Company, Bank of Montreal as Administrative Agent and the lenders party thereto from time to time (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated July 15, 2019).
10.2	Borrowing Base Redetermination Agreement and First Amendment to Amended and Restated Credit Agreement dated as of November 27, 2019, by and among the Company, Bank of Montreal as the Administrative Agent and the lenders party thereto from time to time (incorporated by reference to Exhibit 10.2 to our Annual Report on Form 10-K for Fiscal Year Ended December 31, 2019).
10.3	Borrowing Base Redetermination Agreement and Second Amendment to Amended and Restated Credit Agreement dated as of May 6, 2020 by and among the Company, Bank of Montreal as Administrative Agent and the lenders party thereto from time to time (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the Quarter ended March 31, 2020).
10.4	Third Amendment to Amended and Restated Credit Agreement dated as of June 12, 2020 by and among the Company, Bank of Montreal as Administrative Agent and the lenders party thereto from time to time (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated June 12, 2020).
10.5	Fourth Amendment to Amended and Restated Credit Agreement dated as of August 13, 2020 by and among the Company, Bank of Montreal as Administrative Agent and the lenders party thereto from time to time (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated August 13, 2020).
10.6	Fifth Amendment to Amended and Restated Credit Agreement, dated as of December 4, 2020, by and among the Company, Bank of Montreal as Administrative Agent and the lenders party thereto from time to time (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated December 8, 2020).
10.7	Sixth Amendment to Amended and Restated Credit Agreement, dated as of February 12, 2021, by and among the Company, Wells Fargo Bank, N.A. as Successor Agent and Bank of Montreal as Predecessor Agent and the lenders party thereto from time to time (incorporated by reference to Exhibit 10.7 to our Annual Report on Form 10-K for the year ended December 31, 2020).
10.8	Seventh Amendment to Amended and Restated Credit Agreement dated February 18, 2021, by and among the Company, Wells Fargo Bank, N.A. as Administrative Agent and the lenders party thereto from time to time (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated February 18, 2021).
10.9	Eighth Amendment to Amended and Restated Credit Agreement, dated as of October 22, 2021, by and among the Company, Wells Fargo Bank, N.A. as Administrative Agent and the lenders party thereto from time to time (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the Quarter ended September 30, 2021).
10.10	Amended and Restated Registration Rights Agreement, dated June 7, 2019, by and among the Company, Arkoma Drilling, L.P., Williston Drilling, L.P., Arkoma Drilling CP, LLC, Williston Drilling CP, LLC, New Covey Park Energy LLC and Jerral W. Jones (incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K dated June 7, 2019).
10.11	Amendment No. 1 to the Amended and Restated Registration Rights Agreement, dated December 17, 2019, by and among the Company, Arkoma Drilling, L.P., Williston Drilling, L.P. and New Covey Park Energy LLC incorporated by reference to Exhibit 10.4 to our Annual Report on Form 10-K for the year ended December 31, 2019.
10.12#	Comstock Resources, Inc. 2019 Long-term Incentive Plan Effective as of May 31, 2019 (incorporated by reference to Exhibit 99 to our Registration Statement on Form S-8 dated June 4, 2019).
10.13#	Employment Agreement dated September 7, 2018 by and between the Company and M. Jay Allison (Incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K dated September 7, 2018).
10.14#	Employment Agreement dated September 7, 2018 by and between the Company and Roland O. Burns (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated September 7, 2018).
10.15#	Employment Agreement dated June 22, 2013 by and between the Company (as successor in interest to Covey Park) and David Terry (incorporated by reference to Exhibit 10.8 to our Annual Report on Form 10-K for the year ended December 31, 2019).
10.16	Lease between Stonebriar I Office Partners, Ltd., and Comstock Resources, Inc. dated May 6, 2004 (incorporated by reference to Exhibit 10.24 to our Annual Report on Form 10-K for the year ended December 31, 2004).
10.17	First Amendment to the Lease Agreement dated August 25, 2005, between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. (incorporated by reference to Exhibit 10.19 to our Annual Report on Form 10-K for the year ended December 31, 2005).
10.18	Second Amendment to the Lease Agreement dated October 15, 2007 between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. (incorporated by reference to Exhibit 10.10 to our Annual Report on Form 10-K for the year ended December 31, 2008).

Exhibit No.	Description
10.19	Third Amendment to the Lease Agreement dated September 30, 2008 between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. (incorporated by reference to Exhibit 10.11 to our Annual Report on Form 10-K for the year ended December 31, 2008).
10.20	Fourth Amendment to the Lease Agreement dated May 8, 2009 between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2009).
10.21	Fifth Amendment to the Lease Agreement dated June 15, 2011 between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2011).
10.22	Sixth Amendment to the Lease Agreement dated January 21, 2021 between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. (incorporated by reference to Exhibit 10.20 to our Annual Report on Form 10-K for the year ended December 31, 2020).
21*	Subsidiaries of the Company.
23.1*	Consent of Ernst & Young LLP.
23.2*	Consent of Independent Petroleum Engineers Netherland, Sewell & Associates, Inc.
31.1*	Chief Executive Officer certification under Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Chief Financial Officer certification under Section 302 of the Sarbanes-Oxley Act of 2002.
32.1+	Chief Executive Officer certification under Section 906 of the Sarbanes-Oxley Act of 2002.
32.2+	Chief Financial Officer certification under Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Audit Letter of Netherland, Sewell & Associates, Inc. on Proved Reserves as of December 31, 2021.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Labels Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document
104*	Cover Page Interactive Data File (embedded within the Inline XBRL document)

* Filed herewith.

\+ Furnished herewith.

\# Management contract or compensatory plan document.

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.

COMSTOCK RESOURCES, INC.

By: /s/ M. JAY ALLISON

M. Jay Allison
Chief Executive Officer
(Principal Executive Officer)

Date: February 17, 2022

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/ M. JAY ALLISON M. Jay Allison	Chief Executive Officer and Chairman of the Board of Directors (Principal Executive Officer)	February 17, 2022
/s/ ROLAND O. BURNS Roland O. Burns	President, Chief Financial Officer, Secretary and Director (Principal Financial and Accounting Officer)	February 17, 2022
/s/ ELIZABETH B. DAVIS Elizabeth B. Davis	Director	February 17, 2022
/s/ MORRIS E. FOSTER Morris E. Foster	Director	February 17, 2022
/s/ JIM L. TURNER Jim L. Turner	Director	February 17, 2022

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Comstock Resources, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Comstock Resources, Inc. and subsidiaries (the Company) as of December 31, 2021 and 2020, the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2021, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, in conformity with U.S. generally accepted accounting principles.

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, 2021, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 17, 2022 expressed an unqualified opinion thereon.

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

	Depreciation, Depletion and Amortization of Proved Oil and Gas Properties
Description of the Matter	At December 31, 2021, the net book value of the Company's proved oil and gas properties was $3,700 million, and depreciation, depletion and amortization (DD&A) expense was $469 million for the year then ended. As described in Note 1, under the successful efforts method of accounting, capitalized costs of proved properties are depleted using the units-of-production method based on proved reserves, as estimated by the Company's engineers. Proved oil and gas reserve estimates are based on geological and engineering interpretation and judgment. Significant judgment is required by the Company's engineers in evaluating geological and engineering data when estimating proved oil and gas reserves. Estimating reserves also requires the selection of inputs, including oil and gas price assumptions, future operating and capital cost assumptions and tax rates by jurisdiction, among others. Because of the complexity involved in estimating oil and gas reserves, management used independent petroleum engineers to audit the estimates prepared by the Company's engineers as of December 31, 2021.

Auditing the Company's DD&A calculation is especially complex because of the use of the work of the Company's engineers and the independent petroleum engineers and the evaluation of management's determination of the inputs described above used by the engineers in estimating proved oil and gas reserves.

How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated the design and tested the operating effectiveness of the Company's controls over its process to calculate DD&A, including management's controls over the completeness and accuracy of the financial data provided to the engineers for use in estimating proved oil and gas reserves. Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the Company's engineers responsible for the preparation of the reserve estimates and the independent petroleum engineers used to audit the estimates. In addition, in assessing whether we can use the work of the engineers, we evaluated the completeness and accuracy of the financial data and inputs described above used by the engineers in estimating proved oil and gas reserves by agreeing them to source documentation, and we identified and evaluated corroborative and contrary evidence. For proved undeveloped reserves, we evaluated management's development plan for compliance with SEC requirements. We also tested the mathematical accuracy of the DD&A calculations, including comparing the proved oil and gas reserves amounts used to the Company's reserve report.

/s/ ERNST & YOUNG LLP

We have served as the Company's auditor since 2003.
Dallas, Texas
February 17, 2022

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	As of December 31,	
	2021	2020
ASSETS	*(In thousands)*	
Cash and cash equivalents	$ 30,663	$ 30,272
Accounts receivable:		
Oil and gas sales	217,149	125,016
Joint interest operations	29,755	14,615
From affiliates	20,834	6,155
Derivative financial instruments	5,258	8,913
Other current assets	15,077	14,839
Total current assets	318,736	199,810
Property and equipment:		
Oil and natural gas properties, successful efforts method:		
Proved	4,756,394	4,647,188
Unproved	302,129	332,765
Other	6,690	6,858
Accumulated depreciation, depletion and amortization	(1,058,067)	(902,261)
Net property and equipment	4,007,146	4,084,550
Goodwill	335,897	335,897
Derivative financial instruments	—	661
Operating lease right-of-use assets	6,450	3,025
Other assets	—	40
	$ 4,668,229	$ 4,623,983
LIABILITIES AND STOCKHOLDERS' EQUITY		
Accounts payable	$ 314,569	$ 259,284
Accrued expenses	135,026	133,019
Operating leases	2,444	2,284
Derivative financial instruments	181,945	47,005
Total current liabilities	633,984	441,592
Long-term debt	2,615,235	2,517,149
Deferred income taxes	197,417	200,583
Derivative financial instruments	4,042	2,364
Long-term operating leases	4,075	740
Reserve for future abandonment costs	25,673	19,290
Other non-current liabilities	24	492
Total liabilities	3,480,450	3,182,210
Commitments and contingencies		
Mezzanine equity:		
Series B Convertible Preferred Stock — 5,000,000 shares authorized, 175,000 shares issued and outstanding at December 31, 2021 and 2020, respectively	175,000	175,000
Stockholders' equity:		
Common stock—$0.50 par, 400,000,000 shares authorized, 232,924,646 and 232,414,718 shares issued and outstanding at December 31, 2021 and 2020, respectively	116,462	116,206
Additional paid-in capital	1,100,359	1,095,384
Accumulated earnings (deficit)	(204,042)	55,183
Total stockholders' equity	1,012,779	1,266,773
	$ 4,668,229	$ 4,623,983

The accompanying notes are an integral part of these statements.

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2021	2020	2019
	(In thousands, except per share amounts)		
Revenues:			
Natural gas sales	$ 1,775,768	$ 809,399	$ 635,795
Oil sales	74,962	48,796	132,894
Total oil and gas sales	1,850,730	858,195	768,689
Operating expenses:			
Production and ad valorem taxes	49,141	36,967	35,702
Gathering and transportation	130,940	106,582	71,303
Lease operating	103,467	102,452	80,762
Depreciation, depletion and amortization	469,388	417,112	276,526
General and administrative, net	34,943	32,040	29,244
Exploration	—	27	241
Loss (gain) on sale of assets	162,077	(17)	25
Total operating expenses	949,956	695,163	493,803
Operating income	900,774	163,032	274,886
Other income (expenses):			
Gain (loss) from derivative financial instruments	(560,648)	9,951	51,735
Other income	636	1,080	622
Interest expense	(218,485)	(234,829)	(161,541)
Loss on early extinguishment of debt	(352,599)	(861)	—
Transaction costs	—	—	(41,010)
Total other expenses	(1,131,096)	(224,659)	(150,194)
Income (loss) before income taxes	(230,322)	(61,627)	124,692
Benefit from (provision for) income taxes	(11,403)	9,210	(27,803)
Net income (loss)	(241,725)	(52,417)	96,889
Preferred stock dividends and accretion	(17,500)	(30,996)	(22,415)
Net income (loss) available to common stockholders	$ (259,225)	$ (83,413)	$ 74,474
Net income (loss) per share — basic and diluted	$ (1.12)	$ (0.39)	$ 0.52
Weighted average shares outstanding:			
Basic	231,633	215,194	142,750
Diluted	231,633	215,194	187,378

The accompanying notes are an integral part of these statements.

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Shares	Common Stock-Par Value	Additional Paid-in Capital	Accumulated Earnings (Deficit)	Total
			(In thousands)		
Balance at December 31, 2018	105,871	$ 52,936	$ 452,513	$ 64,122	$ 569,571
Jones Contribution adjustment	—	—	(1,969)	—	(1,969)
Stock-based compensation	841	420	3,600	—	4,020
Income tax withholdings on equity awards	(38)	(19)	(201)	—	(220)
Issuance of common stock	83,333	41,666	456,967	—	498,633
Stock issuance costs	—	—	(1,487)	—	(1,487)
Net income	—	—	—	96,889	96,889
Preferred stock accretion	—	—	—	(4,583)	(4,583)
Payment of preferred dividends	—	—	—	(17,832)	(17,832)
Balance at December 31, 2019	190,007	$ 95,003	$ 909,423	$ 138,596	$ 1,143,022
Stock-based compensation	431	216	6,248	—	6,464
Income tax withholdings on equity awards	(115)	(59)	(633)	—	(692)
Issuance of common stock	42,092	21,046	190,592	—	211,638
Stock issuance costs	—	—	(10,246)	—	(10,246)
Net loss	—	—	—	(52,417)	(52,417)
Preferred stock accretion	—	—	—	(5,417)	(5,417)
Payment of preferred dividends	—	—	—	(25,579)	(25,579)
Balance at December 31, 2020	232,415	$ 116,206	$ 1,095,384	$ 55,183	$ 1,266,773
Stock-based compensation	766	384	6,415	—	6,799
Income tax withholdings on equity awards	(256)	(128)	(1,284)	—	(1,412)
Stock issuance costs	—	—	(156)	—	(156)
Net loss	—	—	—	(241,725)	(241,725)
Payment of preferred dividends	—	—	—	(17,500)	(17,500)
Balance at December 31, 2021	232,925	$ 116,462	$ 1,100,359	$ (204,042)	$ 1,012,779

The accompanying notes are an integral part of these statements.

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2021	2020	2019
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (241,725)	$ (52,417)	$ 96,889
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Deferred and non-current income taxes	(3,565)	(9,409)	28,026
Exploration	—	27	—
Loss (gain) on sale of assets	162,077	(17)	25
Depreciation, depletion and amortization	469,388	417,112	276,526
Loss (gain) on derivative financial instruments	560,648	(9,951)	(51,735)
Cash settlements of derivative financial instruments	(419,714)	134,496	52,684
Amortization of debt discount, premium and issuance costs	21,703	34,038	16,274
Stock-based compensation	6,799	6,464	4,020
Loss on early extinguishment of debt	352,599	861	—
(Increase) decrease in accounts receivable	(121,952)	34,555	3,220
(Increase) decrease in other current assets	(2,033)	7,019	9,823
Increase in accounts payable and accrued expenses	74,780	12,923	15,485
Net cash provided by operating activities	859,005	575,701	451,237
CASH FLOWS FROM INVESTING ACTIVITIES:			
Acquisition of Covey Park Energy LLC, net of cash acquired	—	—	(693,869)
Capital expenditures	(689,210)	(509,690)	(486,781)
Advance payments for drilling costs	—	(1,795)	9,336
Proceeds from sales of assets	138,394	287	475
Net cash used for investing activities	(550,816)	(511,198)	(1,170,839)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings on bank credit facility	555,000	157,000	927,000
Repayments on bank credit facility	(820,000)	(907,000)	(127,000)
Issuance of Senior Notes	2,222,500	751,500	—
Retirement of Senior Notes	(2,210,626)	—	—
Repayment of Covey Park Energy LLC preferred equity	—	—	(533,390)
Issuance of common stock	—	206,626	300,000
Issuance of Series B Convertible Preferred Stock	—	—	175,000
Redemption of Series A Convertible Preferred Stock	—	(210,000)	—
Preferred stock dividends paid	(17,500)	(25,580)	(17,832)
Debt and stock issuance costs	(35,760)	(24,617)	(8,617)
Income tax withholdings related to equity awards	(1,412)	(692)	(220)
Net cash provided by (used for) financing activities	(307,798)	(52,763)	714,941
Net increase (decrease) in cash and cash equivalents	391	11,740	(4,661)
Cash and cash equivalents, beginning of the year	30,272	18,532	23,193
Cash and cash equivalents, end of the year	$ 30,663	$ 30,272	$ 18,532

The accompanying notes are an integral part of these statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Accounting policies used by Comstock Resources, Inc. and subsidiaries reflect oil and natural gas industry practices and conform to accounting principles generally accepted in the United States of America.

Basis of Presentation and Principles of Consolidation

Comstock Resources, Inc. and its subsidiaries are engaged in the acquisition, exploration, development and production of oil and natural gas. The consolidated financial statements include the accounts of Comstock Resources, Inc. and its wholly owned or controlled subsidiaries (collectively, "Comstock" or the "Company"). The Company's operations are primarily focused in North Louisiana and East Texas. All significant intercompany accounts and transactions have been eliminated in consolidation. The Company accounts for its undivided interest in oil and gas properties using the proportionate consolidation method, whereby its share of assets, liabilities, revenues and expenses are included in its financial statements. Net income (loss) and comprehensive income (loss) are the same in all periods presented. All adjustments are of a normal recurring nature unless otherwise disclosed.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual amounts could differ from those estimates. Changes in the future estimated oil and natural gas reserves or the estimated future cash flows attributable to the reserves that are utilized for impairment analyses could have a significant impact on the future results of operations.

Concentration of Credit Risk and Accounts Receivable

Financial instruments that potentially subject the Company to a concentration of credit risk consist principally of cash and cash equivalents, accounts receivable and derivative financial instruments. The Company places its cash with high credit quality financial institutions and its derivative financial instruments with financial institutions and other firms that management believes have high credit ratings. Substantially all of the Company's accounts receivable are due from either purchasers of oil and gas or participants in oil and gas wells for which the Company serves as the operator. Generally, operators of oil and gas wells have the right to offset future revenues against unpaid charges related to operated wells. Oil and gas sales are generally unsecured. The Company's policy is to assess the collectability of its receivables based upon their age, the credit quality of the purchaser or participant and the potential for revenue offset. The Company has not had any significant credit losses in the past and believes its accounts receivable are fully collectible. Accordingly, no allowance for doubtful accounts has been provided.

Other Current Assets

Other current assets at December 31, 2021 and 2020 consist of the following:

	As of December 31,	
	2021	2020
	(In thousands)	
Production tax refunds receivable	$ 7,879	$ 7,915
Pipe and oil field equipment inventory	5,015	3,080
Prepaid expenses	2,183	1,829
Advance payments for drilling costs	—	1,795
Other	—	220
	$ 15,077	$ 14,839

Fair Value Measurements

The Company holds or has held certain financial assets and liabilities that are required to be measured at fair value. These include cash and cash equivalents held in bank accounts and derivative financial instruments. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. A three-level hierarchy is followed for disclosure to show the extent and level of judgment used to estimate fair value measurements:

Level 1 — Inputs used to measure fair value are unadjusted quoted prices that are available in active markets for the identical assets or liabilities as of the reporting date.

Level 2 — Inputs used to measure fair value, other than quoted prices included in Level 1, are either directly or indirectly observable as of the reporting date through correlation with market data, including quoted prices for similar assets and liabilities in active markets and quoted prices in markets that are not active. Level 2 also includes assets and liabilities that are valued using models or other pricing methodologies that do not require significant judgment since the input assumptions used in the models, such as interest rates and volatility factors, are corroborated by readily observable data from actively quoted markets for substantially the full term of the financial instrument.

Level 3 — Inputs used to measure fair value are unobservable inputs that are supported by little or no market activity and reflect the use of significant management judgment. These values are generally determined using pricing models for which the assumptions utilize management's estimates of market participant assumptions.

The following is a reconciliation of the beginning and ending balances for derivative instruments classified as Level 3 in the fair value hierarchy:

	Year Ended December 31,	
	2021	2020
	(In thousands)	
Balance at beginning of year	$ (22,588)	$ 4,351
Total gains (losses) included in earnings	(162,421)	15,943
Settlements, net	58,448	(31,252)
Transfers out of Level 3	126,561	(11,630)
Balance at end of year	$ —	$ (22,588)

The following presents the carrying amounts and the fair values of the Company's financial instruments as of December 31, 2021 and 2020 :

	As of December 31,			
	2021		2020	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Assets:	(In thousands)			
Commodity-based derivatives [(1)]	$ 5,258	$ 5,258	$ 9,574	$ 9,574
Liabilities:				
Commodity-based derivatives [(1)]	185,987	185,987	49,369	49,369
Bank credit facility [(2)]	235,000	235,000	500,000	500,000
7.50% senior notes due 2025 [(3)]	196,998	248,066	473,728	628,691
9.75% senior notes due 2026 [(3)]	—	—	1,577,824	1,769,625
6.75% senior notes due 2029 [(3)]	1,256,874	1,337,500	—	—
5.875% senior notes due 2030 [(3)]	965,000	989,125	—	—

(1) The Company's commodity-based derivatives are classified as Level 2 and measured at fair value using a market approach using third party pricing services and other active markets or broker quotes that are readily available in the public markets.
(2) The carrying value of our floating rate debt outstanding approximates fair value.
(3) The fair value of the Company's fixed rate debt was based on quoted prices as of December 31, 2021 and 2020, respectively, a Level 1 measurement.

Property and Equipment

The Company follows the successful efforts method of accounting for its oil and gas properties. Costs incurred to acquire oil and gas leasehold are capitalized. Acquisition costs for proved oil and gas properties, costs of drilling and equipping productive wells, and costs of unsuccessful development wells are capitalized and amortized on an equivalent unit-of-production basis over the life of the remaining related oil and gas reserves. Equivalent units are determined by converting oil to natural gas at the ratio of one barrel of oil for six thousand cubic feet of natural gas. This conversion ratio is not based on the price of oil or natural gas, and there may be a significant difference in price between an equivalent volume of oil versus natural gas. The estimated future costs of dismantlement, restoration, plugging and abandonment of oil and gas properties and related facilities disposal are capitalized when asset retirement obligations are incurred and amortized as part of depreciation, depletion and amortization expense. Exploration expense includes geological and geophysical expenses and delay rentals related to exploratory oil and gas properties, costs of unsuccessful exploratory drilling and impairments of unproved properties. As of December 31, 2021 and 2020, the unproved properties primarily relate to future drilling locations that were not included in proved undeveloped reserves. Most of these future drilling locations are located on acreage where the reservoir is known to be productive but have been excluded from proved reserves due to uncertainty on whether the wells would be drilled within the next five years as required by SEC rules in order to be included in proved reserves. The costs of unproved properties are transferred to proved oil and gas properties when they are either drilled or they are reflected in proved undeveloped reserves and amortized on an equivalent unit-of-production basis. Costs associated with unevaluated exploratory acreage are periodically assessed for impairment on a property by property basis, and any impairment in value is included in exploration expense. Exploratory drilling costs are initially capitalized as proved property but charged to expense if and when the well is determined not to have found commercial proved oil and gas reserves. Exploratory drilling costs are evaluated within a one-year period after the completion of drilling.

The Company assesses the need for an impairment of the costs capitalized for its proved oil and gas properties when events or changes in circumstances, such as a significant drop in commodity prices, indicate that the Company may not be able to recover its capitalized costs. If impairment is indicated based on undiscounted expected future cash flows attributable to the property, then a provision for impairment is recognized to the extent that net capitalized costs exceed the estimated fair value of the property. The Company determines the fair values of its oil and gas properties using a discounted cash flow model and proved and risk-adjusted probable reserves. Significant Level 3 assumptions associated with the calculation of discounted future cash flows included in the cash flow model include management's outlook for oil and natural gas prices, future oil and natural gas production, production costs, capital expenditures, and the total proved and risk-adjusted probable oil and natural gas reserves expected to be recovered. Management's oil and natural gas price outlook is developed based on third-party longer-term price forecasts as of each measurement date. The expected future net cash flows are discounted using an appropriate discount rate in determining a property's fair value. The oil and natural gas prices used for determining asset impairments will generally differ from those used in the standardized measure of discounted future net cash flows because the standardized measure requires the use of an average price based on the first day of each month of the preceding year. Unproved properties are evaluated for impairment based upon the results of drilling, planned future drilling and the terms of the oil and gas leases.

The Company's estimates of undiscounted future net cash flows attributable to its oil and gas properties may change in the future. The primary factors that may affect estimates of future cash flows include future adjustments, both positive and negative, to proved and appropriate risk-adjusted probable oil and natural gas reserves, results of future drilling activities, future prices for oil and natural gas, and increases or decreases in production and capital costs. As a result of these changes, there may be impairments in the carrying values of our oil and gas properties.

Other property and equipment consists primarily of computer equipment, furniture and fixtures and an airplane which are depreciated over estimated useful lives ranging from three to 31.5 years on a straight-line basis.

Goodwill

The Company had goodwill of $335.9 million as of December 31, 2021 and 2020. Goodwill represents the excess of purchase price over fair value of net tangible and identifiable intangible assets in a business combination.

The Company is required to conduct an annual review of goodwill for impairment and performs the assessment of goodwill on October 1st of each year. If the carrying value of goodwill exceeds the fair value, an impairment charge would be recorded for the difference between fair value and carrying value. The Company performed its quantitative assessment of goodwill as of October 1, 2021 and determined there was no indication of impairment.

Leases

The Company had right-of-use lease assets of $6.5 million and $3.0 million as of December 31, 2021 and 2020, respectively, related to its corporate office lease, certain office equipment and leased vehicles used in oil and gas operations with corresponding short-term and long-term liabilities. The value of the lease assets and liabilities are determined based upon discounted future minimum cash flows contained within each of the respective contracts. The Company determines if contracts contain a lease at inception of the contract. To the extent that contract terms representing a lease are identified, leases are identified as being either an operating lease or a finance-type lease. Comstock currently has no finance-type leases. Right-of-use lease assets representing the Company's right to use an underlying asset for the lease term and the related lease liabilities represent its obligation to make lease payments under the terms of the contracts. Short-term leases that have an initial term of one year or less are not capitalized; however, amounts paid for those leases are included as part of its lease cost disclosures. Short-term lease costs exclude expenses related to leases with a lease term of one month or less.

Comstock contracts for a variety of equipment used in its oil and natural gas exploration and development operations. Contract terms for this equipment vary broadly, including the contract duration, pricing, scope of services included along with the equipment, cancellation terms, and rights of substitution, among others. The Company's drilling operations routinely change due to changes in oil and natural gas prices, demand for oil and natural gas, and the overall operating and economic environment. Comstock accordingly manages the terms of its contracts for drilling rigs so as to allow for maximum flexibility in responding to these changing conditions. The Company's rig contracts are presently either for periods of less than one year, or they are on terms that provide for cancellation with 45 days advance notice without a specified expiration date. Accordingly, the Company has elected not to recognize right-of-use lease assets for these rig contracts. The costs associated with drilling rig operations are accounted for under the successful efforts method, which generally require that these costs be capitalized as part of our proved oil and natural gas properties on our balance sheet unless they are incurred on exploration wells that are unsuccessful, in which case they are charged to exploration expense.

Lease costs recognized during the years ended December 31, 2021, 2020 and 2019 were as follows:

	Year Ended December 31,		
	2021	**2020**	**2019**
		(In thousands)	
Operating lease cost included in general and administrative expense	$ 1,732	$ 1,665	$ 1,646
Operating lease cost included in lease operating expense	879	815	396
Short-term lease cost (drilling rig costs included in proved oil and gas properties)	32,735	33,334	20,527
	$ 35,346	$ 35,814	$ 22,569

Cash payments for operating leases associated with right-of-use assets included in cash provided by operating activities were $2.6 million, $2.5 million and $2.0 million for the years ended December 31, 2021, 2020 and 2019, respectively.

As of December 31, 2021 and 2020, the operating leases had a weighted average remaining term of 2.7 years and 1.5 years, respectively, and the weighted-average discount rate used to determine the present value of future operating lease payments was 2.7% and 4.3%, respectively. The maturities of Comstock's operating lease obligations are as follows:

	(In thousands)
2022	$ 2,589
2023	2,256
2024	1,921
2025	3
Total lease payments	6,769
Imputed interest	(250)
Total lease liability	$ 6,519

Accrued Expenses

Accrued expenses at December 31, 2021 and 2020 consist of the following:

	As of December 31,	
	2021	2020
	(In thousands)	
Accrued interest payable	$ 60,305	$ 67,265
Accrued transportation costs	22,859	25,353
Accrued drilling costs	19,995	24,959
Accrued income and other taxes	15,655	—
Accrued employee compensation	12,320	7,519
Accrued lease operating expenses	2,036	3,466
Other	1,856	3,995
Accrued transaction costs	—	462
	$ 135,026	$ 133,019

Reserve for Future Abandonment Costs

The Company's asset retirement obligations relate to future plugging and abandonment costs of its oil and gas properties and related facilities disposal. The Company records a liability in the period in which an asset retirement obligation is incurred, in an amount equal to the estimated fair value of the obligation that is capitalized. Thereafter, this liability is accreted up to the final retirement cost. Accretion of the discount is included as part of depreciation, depletion and amortization in the accompanying consolidated statements of operations.

The following table summarizes the changes in the Company's total estimated liability:

	Year Ended December 31,	
	2021	2020
	(In thousands)	
Reserve for future abandonment costs at beginning of the year	$ 19,290	$ 18,151
Acquisitions	637	—
New wells placed on production	1,994	733
Changes in estimates and timing	3,008	(699)
Liabilities settled	(31)	(80)
Divestitures	(466)	—
Accretion expense	1,241	1,185
Reserve for future abandonment costs at end of the year	$ 25,673	$ 19,290

Stock-based Compensation

The Company has stock-based employee compensation plans under which stock awards, comprised primarily of restricted stock and performance share units, are issued to employees and non-employee directors. The Company follows the fair value-based method in accounting for equity-based compensation. Under the fair value based method, compensation cost is measured at the grant date based on the fair value of the award and is recognized on a straight-line basis over the award vesting period.

Segment Reporting

The Company presently operates in one business segment, the exploration and production of North American oil and natural gas.

Derivative Financial Instruments and Hedging Activities

The Company accounts for derivative financial instruments (including derivative instruments embedded in other contracts) as either an asset or liability measured at its fair value. Changes in the fair value of derivatives are recognized currently in earnings and in net cash flows from operating activities. The fair value of derivative contracts that expire in less than one year are recognized as current assets or liabilities. Those that expire in more than one year are recognized as long-term assets or liabilities.

Major Purchasers

In 2021, the Company had three major purchasers of its oil and gas production that accounted for 22%, 21%, 13% of its total oil and natural gas sales. In 2020, the Company had four major purchasers of its oil and natural gas production that accounted for 19%, 15%, 15% and 10% of its total oil and natural gas sales. In 2019, the Company had three major purchasers of its oil and natural gas production that accounted for 19%, 16% and 12% of its total oil and natural gas sales. The loss of any of these purchasers would not have a material adverse effect on the Company as there is an available market for its oil and natural gas production from other purchasers.

Revenue Recognition and Gas Balancing

Comstock produces oil and natural gas and reports revenues separately for each of these two primary products in its statements of operations. Revenues are recognized upon the transfer of produced volumes to the Company's customers, who take control of the volumes and receive all the benefits of ownership upon delivery at designated sales points. Payment is reasonably assured upon delivery of production. All sales are subject to contracts that have commercial substance, contain specific pricing terms, and define the enforceable rights and obligations of both parties. These contracts typically provide for cash settlement within 25 days following each production month and are cancellable upon 30 days' notice by either party for oil and vary for natural gas based upon the terms set out in the confirmations between both parties. Prices for sales of oil and natural gas are generally based upon terms that are common in the oil and gas industry, including index or spot prices, location and quality differentials, as well as market supply and demand conditions. As a result, prices for oil and natural gas routinely fluctuate based on changes in these factors. Each unit of production (barrel of crude oil and thousand cubic feet of natural gas) represents a separate performance obligation under the Company's contracts since each unit has economic benefit on its own and each is priced separately according to the terms of the contracts.

Comstock has elected to exclude all taxes from the measurement of transaction prices, and its revenues are reported net of royalties and exclude revenue interests owned by others because the Company acts as an agent when selling crude oil and natural gas, on behalf of royalty owners and working interest owners. Revenue is recorded in the month of production based on an estimate of the Company's share of volumes produced and prices realized. The Company recognizes any differences between estimates and actual amounts received in the month when payment is received. Historically, differences between estimated revenues and actual revenue received have not been significant. The amount of oil or natural gas sold may differ from the amount to which the Company is entitled based on its revenue interests in the properties. The Company did not have any significant imbalance positions at December 31, 2021 or 2020. Sales of oil and natural gas generally occur at or near the wellhead. When sales of oil and gas occur at locations other than the wellhead, the Company accounts for costs incurred to transport the production to the delivery point as gathering and transportation expenses. The Company has recognized accounts receivable of $217.1 million and $125.0 million as of December 31, 2021 and 2020, respectively, from customers for contracts where performance obligations have been satisfied and an unconditional right to consideration exists.

General and Administrative Expenses

General and administrative expenses are reported net of reimbursements of overhead costs that are received from working interest owners of the oil and gas properties operated by the Company of $25.3 million, $24.7 million and $16.8 million for the years ended December 31, 2021, 2020 and 2019, respectively.

Income Taxes

The Company accounts for income taxes using the asset and liability method, whereby deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax basis, as well as the tax consequences attributable to the future utilization of existing net operating loss and other carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that the change in rate is enacted.

Earnings Per Share

Unvested restricted stock are included in common stock outstanding and are considered to be participating securities as such shares have a non-forfeitable right to participate in any dividends that might be declared and have the right to vote on matters submitted to the Company's stockholders. Accordingly, shares of unvested restricted stock are included in the computation of basic and diluted earnings per share pursuant to the two-class method.

Weighted average shares of unvested restricted stock included in common stock outstanding were as follows:

	Year Ended December 31,		
	2021	2020	2019
		(in thousands)	
Unvested restricted stock	1,057	1,149	685

Performance share units ("PSUs") represent the right to receive a number of shares of the Company's common stock that may range from zero to up to two times the number of PSUs granted on the award date based on the achievement of certain performance measures during a performance period. The number of potentially dilutive shares related to PSUs is based on the number of shares, if any, which would be issuable at the end of the respective period, assuming that date was the end of the performance period. The treasury stock method is used to measure the dilutive effect of PSUs.

	Year Ended December 31,		
	2021	2020	2019
	(In thousands, except per unit amounts)		
Weighted average PSUs	929	632	776
Weighted average grant date fair value per unit	$8.11	$9.33	$9.56

The Series A and Series B Convertible Preferred Stock were convertible into 52,500,000 and 43,750,000 shares of common stock, respectively. The Company redeemed all of the shares of Series A Convertible Preferred Stock on May 19, 2020. The dilutive effect of preferred stock is computed using the if-converted method as if conversion of the preferred shares had occurred at the earlier of the date of issuance or the beginning of the period. Weighted average shares of convertible preferred stock outstanding were as follows:

	Year Ended December 31,		
	2021	2020	2019
		(In thousands)	
Weighted average convertible preferred stock	43,750	63,832	44,565

None of the Company's participating securities participate in losses and as such are excluded from the computation of basic earnings per share during periods of net losses.

Basic and diluted earnings per share were determined as follows:

	Year Ended December 31,		
	2021	2020	2019
	(In thousands, except per share amounts)		
Net income (loss) available to common stockholders	$ (259,225)	$ (83,413)	$ 74,474
Income allocable to unvested restricted shares	—	—	(356)
Basic net income (loss) available to common stockholders	$ (259,225)	$ (83,413)	$ 74,118
Income allocable to convertible preferred stock	—	—	22,415
Diluted net income (loss) available to common stockholders	$ (259,225)	$ (83,413)	$ 96,533
Basic weighted average shares outstanding	231,633	215,194	142,750
Effect of dilutive securities:			
Performance stock units	—	—	63
Convertible preferred stock	—	—	44,565
Diluted weighted average shares outstanding	231,633	215,194	187,378
Basic income (loss) per share	$ (1.12)	$ (0.39)	$ 0.52
Diluted income (loss) per share	$ (1.12)	$ (0.39)	$ 0.52

Basic and diluted per share amounts are the same for the year ended December 31, 2021 and 2020 due to the net loss in those periods.

Supplementary Information With Respect to the Consolidated Statements of Cash Flows

For the purpose of the consolidated statements of cash flows, the Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Cash payments made for interest and income taxes and other non-cash investing and financing activities were as follows:

	Year Ended December 31,		
	2021	2020	2019
		(In thousands)	
Cash payments for:			
Interest payments	$ 203,742	$ 228,555	$ 149,039
Income tax (payments) refunds	$ (149)	$ 10,218	$ (2)
Non-cash investing activities include:			
Increase (decrease) in accrued capital expenditures	$ (4,964)	$ (17,234)	$ 24,273
Liabilities assumed in exchange for right-of-use lease assets	$ 5,847	$ 1,761	$ 5,372
Non-cash investing and financing activities related to acquisitions:			
Issuance of common stock	$ —	$ —	$ 198,633
Issuance of Series A Convertible Preferred Stock	$ —	$ —	$ 200,000
Assumed 7.5% senior notes	$ —	$ —	$ 446,625
Acquired working capital	$ —	$ 520	$ 41,365
Non-cash financing activities include:			
Retirement of debt in exchange for common stock	$ —	$ (4,151)	$ —
Issuance of common stock in exchange for debt	$ —	$ 5,012	$ —

(2) Acquisitions and Dispositions of Oil and Gas Properties

Acquisitions

In 2021, the Company acquired a 50% interest in approximately 35,000 net acres of predominantly undeveloped Haynesville shale acreage in East Texas from an unaffiliated third party, which also included interests in 37 producing wells for $34.7 million of cash consideration. During 2021 and 2020, the Company acquired 32,556 and 13,519 net acres through acquisitions or direct leasing for $22.9 million and $7.9 million, respectively.

On November 1, 2019, Comstock acquired a privately held company with producing properties and acreage in the Haynesville shale in exchange for 4,500,000 newly issued shares of the Company's common stock. The transaction was valued at approximately $42.3 million.

On July 16, 2019, Comstock acquired Covey Park Energy LLC ("Covey Park") for total consideration of $700.0 million of cash, the issuance of Series A Convertible Preferred Stock with a redemption value of $210.0 million, and the issuance of 28,833,000 shares of common stock (the "Covey Park Acquisition"). In addition to the consideration paid, Comstock assumed $625.0 million of Covey Park's 7.5% senior notes, repaid $380.0 million of Covey Park's then outstanding borrowings under its bank credit facility and redeemed all of Covey Park's preferred equity for $153.4 million. Based on the fair value of the preferred stock issued and the closing price of the Company's common stock of $5.82 per share on July 16, 2019, the transaction was valued at approximately $2.2 billion. Covey Park's operations were focused primarily in the Haynesville/Bossier shale in East Texas and North Louisiana. Funding for the cash consideration was provided by the sale of 50 million newly issued shares of common stock for $300.0 million and 175,000 shares of newly issued Series B Convertible Preferred Stock for $175.0 million to the Company's majority shareholder and by borrowings under Comstock's bank credit facility and cash on hand. Comstock incurred $41.0 million of advisory and legal fees and other acquisition-related costs in connection with the acquisition. These acquisition costs are included in transaction costs in the Company's consolidated statements of operations.

The transaction was accounted for as a business combination, using the acquisition method. The purchase price allocation of the assets acquired and liabilities assumed was finalized in the third quarter of 2020.

The Series A Convertible Preferred Stock was issued with a face value of $210.0 million. Management retained a third-party valuation firm to assess the fair value of the preferred stock. A yield methodology using Level 2 inputs of the Company's publicly traded debt, including the assumption of Covey Park's 7.5% senior notes, resulted in a fair value of $200.0 million. On May 19, 2020, the Company redeemed the 210,000 outstanding shares of the Series A Convertible Preferred Stock for an aggregate redemption price of $210.0 million plus accrued and unpaid dividends of approximately $2.9 million.

The fair values determined for accounts receivable, accounts payable, accrued drilling costs and other current liabilities were equivalent to the carrying value due to their short-term nature. The fair value of the proved and unproved oil and natural gas properties was derived from estimated future discounted net cash flows, a Level 3 measurement, based on existing production curves and timing of development of those properties. The key factors used in deriving the estimated future cash flows include estimated recoverable reserves, production rates, future operating and development costs, and future commodity prices. Key inputs to the valuation included average oil prices of $74.80 per barrel and average natural gas prices of $3.32 per Mcf utilizing a combination of third-party price estimates and management price forecasts as of the acquisition date. The resulting estimated future cash flows from the acquired assets were discounted at rates ranging from 10% - 25% depending on risk characteristics of reserve categories acquired. Management utilized the assistance of an independent reserve firm and internal resources to estimate the fair value of the oil and natural gas properties.

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

The fair value of the asset retirement obligations of $5.4 million was included in oil and natural gas properties with the corresponding liability in noncurrent liabilities. The fair value was based on a discounted cash flow model that included assumptions of current abandonment costs, inflation rates, discount rates and timing of actual abandonment and restoration activities. Due to the inputs and significant assumptions associated with the estimation of asset retirement obligations, the estimates made by management represent Level 3 inputs.

The Covey Park Acquisition qualified as a tax free merger whereby the Company acquired carryover tax basis in Covey Park's assets and liabilities, adjusted for differences between the purchase price allocated to the assets acquired and liabilities assumed based on the fair value and the carryover tax basis.

Dispositions

On November 16, 2021, the Company sold its non-operated properties in the Bakken shale for $138.1 million after selling expenses. The properties sold included non-operated interests in 442 producing wells (68.3 net) producing approximately 4,500 barrels of oil equivalent per day. The Company incurred a $162.2 million pre-tax loss on the divestiture.

(3) Oil and Gas Producing Activities

Set forth below is certain information regarding the aggregate capitalized costs of oil and gas properties and costs incurred by the Company for its oil and natural gas property acquisition, development and exploration activities:

Capitalized Costs

	As of December 31,	
	2021	2020
	(In thousands)	
Proved properties:		
Leasehold costs	$ 3,053,783	$ 3,010,760
Wells and related equipment and facilities	1,702,611	1,636,428
Accumulated depreciation depletion and amortization	(1,056,317)	(901,003)
	3,700,077	3,746,185
Unproved properties	302,129	332,765
	$ 4,002,206	$ 4,078,950

Costs Incurred

	Year Ended December 31,		
	2021	2020	2019
		(In thousands)	
Property acquisitions:			
Proved property	$ 21,781	$ —	$ 1,854,541
Unproved property	35,871	7,949	237,210
Exploration and development:			
Development leasehold costs	12,953	13,022	7,603
Exploratory drilling and completion costs	6,966	—	—
Development drilling and completion costs	569,141	436,074	493,625
Other development costs	39,168	34,572	2,490
Change to asset retirement obligations	5,608	(47)	12,549
Total capital expenditures	$ 691,488	$ 491,570	$ 2,608,018

(4) Exploratory Well Costs

Exploratory well costs are initially capitalized as proved property in the consolidated balance sheets but charged to exploration expense if and when the well is determined not to have found commercial proved oil and gas reserves, it is impaired or it is sold. The changes in capitalized exploratory well costs are as follows:

	Year Ended December 31, 2021
	(in thousands)
Beginning capitalized exploratory project costs	$ —
Additions to exploratory well costs pending the determination of proved reserves	6,966
Ending capitalized exploratory well costs	$ 6,966

As of December 31, 2021, the Company had no exploratory wells for which costs have been capitalized for a period greater than one year.

(5) Long-term Debt

Long-term debt is comprised of the following:

	As of December 31,	
	2021	2020
	(In thousands)	
Bank Credit Facility:		
Principal	$ 235,000	$ 500,000
Debt issuance costs, net of amortization	(38,637)	(34,403)
7.5% Senior Notes due 2025:		
Principal	244,400	619,400
Discount, net of amortization	(47,402)	(145,672)
9.75% Senior Notes due 2026:		
Principal	—	1,650,000
Discount, net of amortization	—	(72,176)
6.75% Senior Notes Due 2029:		
Principal	1,250,000	—
Premium, net of amortization	6,874	—
5.875% Senior Notes Due 2030:		
Principal	965,000	—
	$ 2,615,235	$ 2,517,149

The premiums and discounts on the senior notes are being amortized over the lives of the senior notes using the effective interest rate method. Issuance costs are amortized over the lives of the senior notes on a straight-line basis which approximates the amortization that would be calculated using an effective interest rate method.

The following table summarizes Comstock's principal amount of debt as of December 31, 2021 by year of maturity:

	2022	2023	2024	2025	2026	Thereafter	Total
				(In thousands)			
Bank credit facility	$ —	$ —	$ 235,000	$ —	$ —	$ —	$ 235,000
7.5% Senior Notes due 2025	—	—	—	244,400	—	—	244,400
6.75% Senior Notes due 2029	—	—	—	—	—	1,250,000	1,250,000
5.875% Senior Notes due 2030	—	—	—	—	—	965,000	965,000
	$ —	$ —	$ 235,000	$ 244,400	$ —	$2,215,000	$2,694,400

As of December 31, 2021 the Company had $235.0 million outstanding under a bank credit facility with a $1.4 billion borrowing base which is re-determined on a semi-annual basis and upon the occurrence of certain other events and matures on July 16, 2024. Borrowings under the bank credit facility are secured by substantially all of the assets of the Company and its subsidiaries and bear interest at the Company's option, at either LIBOR plus 2.25% to 3.25% or a base rate plus 1.25% to 2.25%, in each case depending on the utilization of the borrowing base. The Company also pays a commitment fee of 0.375% to 0.5% on the unused borrowing base. The weighted average interest rate on borrowings under the bank credit facility were 2.71% and 3.48% as of December 31, 2021 and 2020, respectively. The bank credit facility places certain restrictions upon the Company's and its subsidiaries' ability to, among other things, incur additional indebtedness, pay cash dividends, repurchase common stock, make certain loans, investments and divestitures and redeem the senior notes. The only financial covenants are the maintenance of a last twelve month leverage ratio of less than 4.0 to 1.0 and an adjusted current ratio of at least 1.0 to 1.0. The Company was in compliance with the covenants as of December 31, 2021.

In March 2021, the Company issued $1.25 billion principal amount of 6.75% senior notes due 2029 (the "2029 Notes") in a private placement and received net proceeds after offering costs of $1.24 billion, which were used to repurchase a portion of the Company's 7.5% senior notes due 2025 and 9.75% senior notes due 2026 (the "2026 Notes") pursuant to a tender offer. The 2029 Notes mature on March 1, 2029 and accrue interest at a rate of 6.75% per annum, payable semi-annually on March 1 and September 1 of each year.

Pursuant to the tender offer, Comstock repurchased $375.0 million principal amount of its 7.50% senior notes due 2025 and $777.1 million principal amount of the 2026 Notes for an aggregate amount of $1.26 billion, which included premiums paid over face value of $97.9 million, accrued interest of $12.5 million and $1.1 million of costs related to the tender offer.

In June 2021, the Company issued $965.0 million principal amount of its 5.875% senior notes due 2030 (the "2030 Notes") in a private placement and received net proceeds after offering costs of $949.5 million, which were used along with cash on hand to redeem all outstanding 2026 Notes. The 2030 Notes mature on January 15, 2030 and accrue interest at a rate of 5.875% per annum, payable semi-annually on January 15 and July 15 of each year.

In June 2021, Comstock completed the redemption of all outstanding 2026 Notes for an aggregate amount of $978.6 million, which included premiums paid over face value of $74.0 million and accrued interest of $31.7 million.

As a result of the early retirement of the senior notes repurchased in the tender offer and the redemption of the 2026 Notes, the Company recognized a loss of $352.6 million on early retirement of debt for the year ended December 31, 2021.

In May 2020, the Company exchanged 767,096 shares of its common stock, valued at approximately $5.0 million, to retire $5.6 million aggregate principal amount of the Company's 7.5% Senior Notes due 2025, which had a carrying value of $4.2 million. As a result, the Company recognized a $0.9 million loss on early retirement of debt in 2020.

In 2020, the Company issued $800.0 million principal amount of its 9.75% Senior Notes due 2026 in an underwritten offering and received net proceeds of $737.1 million, which were used to repay borrowings under the Company's bank credit facility.

(6) Commitments and Contingencies

The Company has natural gas transportation and gathering contracts which extend to 2031. Commitments under these contracts are $41.2 million for 2022, $41.5 million for 2023, $41.6 million for 2024, $29.8 million for 2025, $25.0 million for 2026 and $24.8 million for 2027 through 2030.

The Company has drilling rig contracts and completion service contracts. Terms of drilling contracts vary from well to well, or are for periods of less than one year. The service contracts are generally for terms ranging from 45 days to six months. Existing commitments under these contracts is $12.3 million as of December 31, 2021.

In April 2021, the Company entered into a well stimulation agreement that extends to 2024 for exclusive use of a natural gas powered pressure pumping fleet. The minimum commitment under this contract is $19.2 million per year from 2022 through 2024. The fleet is expected to be put into service in April 2022.

From time to time, the Company is involved in certain litigation that arise in the normal course of its operations. The Company records a loss contingency for these matters when it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. The Company does not believe the resolution of these matters will have a material adverse effect on the Company's financial position, results of operations or cash flows and no material amounts are accrued relative to these matters at December 31, 2021 or 2020.

(7) Convertible Preferred Stock

In connection with the Covey Park Acquisition, the Company issued 210,000 shares of Series A Convertible Preferred Stock with a face value of $210.0 million and a fair value of $200.0 million as part of the consideration for the acquisition and sold 175,000 shares of Series B Convertible Preferred Stock for $175.0 million to its majority stockholder. On May 19, 2020, the Company redeemed the 210,000 outstanding shares of the Series A Convertible Preferred Stock for an aggregate redemption price of $210.0 million plus accrued and unpaid dividends of approximately $2.9 million. The holder of the Series B Convertible Preferred Stock is entitled to receive quarterly dividends at a rate of 10% per annum, which are paid in arrears. The holder of the Series B Convertible Preferred Stock may convert any or all shares of such preferred stock into shares of the Company's common stock at $4.00 per share, subject to adjustment pursuant to customary anti-dilution provisions. The Company has the right to redeem the Series B Convertible Preferred Stock at any time at face value plus accrued dividends. The Series B Convertible Preferred Stock is classified as mezzanine equity based on the majority stockholder's ability to control the terms of conversion to common stock.

(8) Stockholders' Equity

The authorized capital of the Company is 405,000,000 shares, of which 400,000,000 shares are common stock, $0.50 par value per share, and 5,000,000 are preferred stock, $10.00 par value per share.

In May 2020, the Company completed an underwritten public offering of its common stock and issued and sold 41,325,000 shares for net proceeds after offering costs of $196.4 million. The proceeds of the offering were used toward the redemption of the Series A Convertible Preferred Stock.

(9) Stock-based Compensation

The Company grants restricted shares of common stock and PSUs to key employees and directors as part of their compensation. Grants are made pursuant to the Company's 2019 Long-term Incentive Plan (the "2019 Plan"), which was approved by the Company's shareholders on May 31, 2019. Future awards of performance share units, restricted stock grants or other equity awards available under the 2019 Plan as of December 31, 2021 were 4,439,784 shares of common stock.

Stock-based compensation expense is included in general and administrative expenses. During the years ended December 31, 2021, 2020 and 2019 the Company had $6.8 million, $6.5 million and $4.0 million, respectively, in stock-based compensation expense.

Restricted Stock

The fair value of restricted stock grants is amortized over the vesting period, generally one year to three years, using the straight-line method. The fair value of each restricted share on the date of grant is equal to the market price of a share of the Company's stock.

A summary of restricted stock activity is presented below:

	Number of Restricted Shares	Weighted Average Grant Price
Outstanding at January 1, 2021	1,038,006	$5.80
Granted	473,162	$6.05
Vested	(543,695)	$6.13
Forfeitures	(14,502)	$5.58
Outstanding at December 31, 2021	952,971	$5.74

	Year Ended December 31,		
	2021	2020	2019
	(In thousands, except per share data)		
Fair value of vested restricted stock	$ 3,070	$ 2,852	$ 925
Per share weighted average fair value	$ 6.05	$ 5.38	$ 5.40
Compensation expense recognized for restricted stock grants	$ 3,406	$ 3,247	$ 2,121
Unrecognized compensation expense related to unvested shares	$ 3,939		
Expected recognition period	1.7 years		

Performance Share Units

The Company issues PSUs as part of its long-term equity incentive compensation. PSU awards can result in the issuance of common stock to the holder if certain performance criteria are met during a performance period. The performance periods consist of three years. The performance criteria for the PSUs are based on the Company's annualized total stockholder return ("TSR") for the performance period as compared with the TSR of certain peer companies for the performance period. The costs associated with PSUs are recognized as general and administrative expense over the performance periods of the awards.

The fair value of PSUs was measured at the grant date using the Geometric Brownian Motion Model ("GBM Model"). Significant assumptions used in this simulation include the Company's expected volatility and a risk-free interest rate based on U.S. Treasury yield curve rates with maturities consistent with the vesting periods, as well as the volatilities for each of the Company's peers. Assumptions regarding volatility included the historical volatility of each company's stock and the implied volatilities of publicly traded stock options.

Significant assumptions used to value PSUs included:

	Year Ended December 31,		
	2021	2020	2019
Risk free interest rate	0.3 %	0.3 %	1.5 %
Range of implied volatility:			
Minimum	37 %	39 %	32 %
Maximum	83 %	198 %	84 %

A summary of PSU activity is presented below:

	Number of PSUs	Weighted Average Grant Price
Outstanding at January 1, 2021	1,136,488	$9.33
Granted	220,929	$8.56
Forfeitures	(307,507)	$12.93
Outstanding at December 31, 2021	1,049,910	$8.11

	Year Ended December 31,		
	2021	2020	2019
	(In thousands, except per unit data)		
Number of PSUs granted	221	232	619
Grant date fair value	$ 1,891	$ 1,943	$ 4,857
Grant date fair value per unit	$ 8.56	$ 8.37	$ 7.85
Compensation expense recognized for PSUs	$ 3,392	$ 3,217	$ 1,899
Unrecognized compensation expense related to unvested shares	$ 3,444		
Expected recognition period	1.6 years		

The fair value of PSUs is amortized over the vesting period of three years, using the straight-line method. The final number of shares of common stock issued may vary depending upon the performance multiplier, and can result in the issuance of zero to 2,099,820 shares of common stock based on the achieved performance ranges from zero to two hundred percent.

(10) Retirement Plan

The Company has a 401(k) profit sharing plan which covers all of its employees. At its discretion, Comstock may match the employees' contributions to the plan. Matching contributions to the plan were approximately $1.3 million, $1.3 million and $1.0 million for the years ended December 31, 2021, 2020 and 2019, respectively.

(11) Income Taxes

Deferred income taxes are provided to reflect the future tax consequences or benefits of differences between the tax basis of assets and liabilities and their reported amounts in the financial statements using enacted tax rates.

The following is an analysis of the consolidated income tax provision (benefit):

	Year Ended December 31,		
	2021	2020	2019
	(In thousands)		
Current - Federal	$ —	$ —	$ —
Current - State	14,968	(154)	(223)
Deferred - Federal	(16,721)	(12,037)	27,550
Deferred - State	13,156	2,981	476
	$ 11,403	$ (9,210)	$ 27,803

In recording deferred income tax assets, the Company considers whether it is more likely than not that its deferred income tax assets will be realized in the future. The ultimate realization of deferred income tax assets is dependent upon the generation of future taxable income during the periods in which those deferred income tax assets would be deductible. The Company believes that after considering all the available objective evidence, historical and prospective, with greater weight given to historical evidence, management is not able to determine that it is more likely than not that all of its deferred tax assets will be realized. As a result, the Company established valuation allowances for its deferred tax assets and U.S. federal and state net operating loss carryforwards that are not expected to be utilized due to the uncertainty of generating taxable income prior to the expiration of the carryforward periods. The Company will continue to assess the valuation allowances against deferred tax assets considering all available information obtained in future periods.

The tax effects of significant temporary differences representing the net deferred tax liabilities were as follows:

	As of December 31, 2021	2020
	(In thousands)	
Deferred tax assets:		
Interest expense limitation	$ 103,771	$ 55,026
Net operating loss carryforwards	53,112	59,335
Unrealized hedging losses	37,953	10,452
Asset retirement obligation	4,312	4,061
Other	7,771	5,661
	206,919	134,535
Valuation allowance on deferred tax assets	(46,474)	(15,964)
Deferred tax assets	160,445	118,571
Deferred tax liabilities:		
Property and equipment	(340,722)	(283,959)
Bond discount	(9,954)	(30,591)
Other	(7,186)	(4,604)
Deferred tax liabilities	(357,862)	(319,154)
Net deferred tax liability	$ (197,417)	$ (200,583)

The difference between the customary rate of 21% and the effective tax rate on income (losses) is due to the following:

	Year Ended December 31, 2021	2020	2019
		(In thousands)	
Tax at statutory rate	$ (48,368)	$ (12,941)	$ 26,185
Tax effect of:			
Valuation allowance on deferred tax assets	30,504	(919)	(494)
State income taxes, net of federal benefit	28,117	3,746	(499)
Nondeductible transaction costs	—	—	1,417
Nondeductible stock-based compensation	1,825	1,109	886
Other	(675)	(205)	308
Total	$ 11,403	$ (9,210)	$ 27,803

	Year Ended December 31, 2021	2020	2019
Tax at statutory rate	21.0 %	21.0 %	21.0 %
Tax effect of:			
Valuation allowance on deferred tax assets	(13.3)	1.5	(0.4)
State income taxes, net of federal benefit	(12.2)	(6.1)	(0.4)
Nondeductible transaction costs	—	—	1.1
Nondeductible stock-based compensation	(0.8)	(1.8)	0.7
Other	0.3	0.3	0.3
Effective tax rate	(5.0)%	14.9 %	22.3 %

At December 31, 2021, Comstock had the following carryforwards available to reduce future income taxes:

Types of Carryforward	Years of Expiration Carryforward	Amount
		(In thousands)
Net operating loss – U.S. federal	2022-2037	$ 899,953
Net operating loss – U.S. federal	Unlimited	$ 6,627
Net operating loss – state taxes	Unlimited	$ 1,461,613
Interest expense – U.S. federal	Unlimited	$ 494,147
Interest expense – state taxes	Unlimited	$ 215,349

The Company's ability to use net operating losses ("NOLs") generated before its ownership change in 2018 to reduce taxable income is generally limited to an annual amount based on the fair market value of its stock immediately prior to the ownership change multiplied by the long-term tax-exempt interest rate. The Company's NOLs are estimated to be limited to $3.3 million a year as a result of this limitation. In addition to this limitation, IRC Section 382 provides that a corporation with a net unrealized built-in gain immediately before an ownership change may increase its limitation by the amount of built-in gain recognized during a recognition period, which is generally the five-year period immediately following an ownership change. Based on the fair market value of the Company's common stock immediately prior to the ownership change, Comstock believes that it has a net unrealized built-in gain which will increase the Section 382 limitation during the five-year recognition period by $117.0 million.

NOLs that exceed the Section 382 limitation in any year continue to be allowed as carry forwards until they expire and can be used to offset taxable income for years within the carryover period subject to the limitation in each year. NOLs incurred prior to 2018 generally have a 20-year life until they expire. NOLs generated in 2018 and after would be carried forward indefinitely. Comstock's use of new NOLs arising after the date of an ownership change would not be affected by the 382 limitation. If the Company does not generate a sufficient level of taxable income prior to the expiration of the pre-2018 NOL carry-forward periods, then it will lose the ability to apply those NOLs as offsets to future taxable income. The Company estimates that $834.6 million of the U.S. federal NOL carryforwards and $1.3 billion of the estimated state NOL carryforwards will expire unused.

The Company's federal income tax returns for the years subsequent to December 31, 2016 remain subject to examination. The Company's income tax returns in major state income tax jurisdictions remain subject to examination for various periods subsequent to December 31, 2018. The Company currently believes that its significant filing positions are highly certain and that all of its other significant income tax filing positions and deductions would be sustained upon audit or the final resolution would not have a material effect on the consolidated financial statements. Therefore, the Company has not established any significant reserves for uncertain tax positions.

(12) Derivative Financial Instruments and Hedging Activities

Comstock uses commodity price swaps, basis swaps and collars to hedge oil and natural gas prices to manage price risk. Swaps are settled monthly based on differences between the prices specified in the instruments and the settlement prices of futures contracts. Generally, when the applicable settlement price is less than the price specified in the contract, Comstock receives a settlement from the counterparty based on the difference multiplied by the volume or amounts hedged. Similarly, when the applicable settlement price exceeds the price specified in the contract, Comstock pays the counterparty based on the difference. Comstock generally receives a settlement from the counterparty for floors when the applicable settlement price is less than the price specified in the contract, which is based on the difference multiplied by the volumes hedged. For collars, generally Comstock receives a settlement from the counterparty when the settlement price is below the floor and pays a settlement to the counterparty when the settlement price exceeds the cap. No settlement occurs when the settlement price falls between the floor and cap.

All of the Company's derivative financial instruments are used for risk management purposes and, by policy, none are held for trading or speculative purposes. Comstock minimizes credit risk to counterparties of its derivative financial instruments through formal credit policies, monitoring procedures, and diversification. The Company is not required to provide any credit support to its counterparties other than cross collateralization with the assets securing its bank credit facility. None of the Company's derivative financial instruments involve payment or receipt of premiums. The Company classifies the fair value amounts of derivative financial instruments as net current or noncurrent assets or liabilities, whichever the case may be, by commodity contract. None of the Company's derivative contracts are designated as cash flow hedges. The Company recognizes cash settlements and changes in the fair value of its derivative financial instruments as a single component of other income (expenses) in the consolidated statements of operations and as separate components within cash flows from operating activities in the consolidated statements of cash flows.

All of Comstock's natural gas derivative financial instruments are tied to the Henry Hub-NYMEX price index and all of its oil derivative financial instruments have been tied to the WTI-NYMEX index price.

The Company had the following outstanding natural gas price derivative financial instruments at December 31, 2021:

	Future Production Period Ending December 31,		
	2022	**2023**	**Total**
Natural Gas Swap Contracts:			
Volume (MMBtu)	121,300,000	—	121,300,000
Average Price per MMBtu	$2.67		$2.67
Natural Gas Collar Contracts:			
Volume (MMBtu)	140,925,000	6,750,000	147,675,000
Price per MMBtu:			
Average Ceiling	$3.91	$4.03	$3.92
Average Floor	$2.62	$2.67	$2.63
Natural Gas Basis Swap Contracts:			
Volume (MMBtu)	10,950,000 [1]	—	10,950,000
Average Price per MMBtu	($0.16) [1]		($0.16)

(1) Contracts fix the differentials between NYMEX Henry Hub and the Columbia Gulf Mainline indices.

The aggregate fair value of the Company's derivative financial instruments are presented on a gross basis in the accompanying consolidated balance sheets. The classification of derivative financial instruments between assets and liabilities, consists of the following:

		As of December 31,	
Type	**Consolidated Balance Sheet Location**	**2021**	**2020**
		(in thousands)	
Asset Derivative Financial Instruments:			
Natural gas price derivatives	Derivative Financial Instruments – current	$ 4,528	$ 8,913
Oil price derivatives	Derivative Financial Instruments – current	730	—
		$ 5,258	$ 8,913
Natural gas price derivatives	Derivative Financial Instruments – long-term	$ —	$ 661
Liability Derivative Financial Instruments:			
Natural gas price derivatives	Derivative Financial Instruments – current	$ 181,215	$ 45,158
Oil price derivatives	Derivative Financial Instruments – current	730	831
Interest rate derivatives	Derivative Financial Instruments – current	—	1,016
		$ 181,945	$ 47,005
Natural gas price derivatives	Derivative Financial Instruments – long-term	$ 4,042	$ 1,308
Interest rate derivatives	Derivative Financial Instruments – long-term	—	1,056
		$ 4,042	$ 2,364

Gains and losses related to the change in the fair value of the Company's derivative contracts recognized in the consolidated statement of operations were as follows:

Gain/(Loss) Recognized in Earnings on Derivatives	Year Ended December 31, 2021	2020	2019
		(In thousands)	
Natural gas price derivatives	$ (555,636)	$ 353	$ 60,694
Oil price derivatives	(7,247)	12,059	(8,959)
Interest rate derivatives	2,235	(2,461)	—
	$ (560,648)	$ 9,951	$ 51,735

(13) Related Party Transactions

The Company operates oil and natural gas properties held by a partnership owned by its majority stockholder. Comstock also drills and operates certain other properties for the partnership that the Company does not own working interest in. Comstock charges the partnership for the costs incurred to drill, complete and produce the wells, as well as drilling and operating overhead fees that are charged other interest owners. Comstock also provides natural gas marketing services to the partnership, including evaluating potential markets and providing hedging services, in return for a fee equal to $0.02 per Mcf for natural gas marketed. The Company received $1.4 million, $718 thousand and $134 thousand in 2021, 2020 and 2019, respectively, for operating and marketing services provided to the partnership.

Comstock had a $20.8 million and $6.2 million receivable from the partnership at December 31, 2021 and 2020, respectively. In addition, derivative financial instruments at December 31, 2021 and 2020 included a $2.3 million receivable and $2.0 million payable, respectively, for oil and natural gas price hedging contracts that the Company has entered into with the partnership.

In 2021, the Company acquired from unaffiliated third parties a 50% interest in approximately 35,000 net acres of predominantly undeveloped Haynesville shale acreage in East Texas, which also included interests in 37 producing wells. An affiliate of the Company's majority stockholder acquired the remaining 50% of the acreage and wells alongside Comstock. Comstock will be the operator of the future drilling program on the jointly acquired acreage.

In February 2019, Comstock sold certain leases covering 1,464 undeveloped net acres in Caddo Parish, Louisiana for $5.9 million to a partnership owned by the Company's majority stockholder. The proceeds from the sale were used to fund the purchase of a like number of net acres from a third party for $5.9 million. The acreage acquired was in part the acreage sold to the partnership or acreage in the same area. The purchase price paid per net acre was determined by the price paid by the Company to the third party.

(14) Oil and Gas Reserves Information (Unaudited)

Set forth below is a summary of the Company's proved oil and natural gas reserves:

	Year Ended December 31,					
	2021		2020		2019	
	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Proved Reserves:						
Beginning of period	11,000	5,562,876	16,747	5,341,497	23,612	2,282,758
Revisions of previous estimates	145	88,546	(4,241)	306,552	(4,621)	62,697
Extensions and discoveries	—	797,198	2	365,663	259	315,286
Acquisitions of minerals in place	—	202,588	—	—	240	3,023,109
Sales of minerals in place	(9,308)	(43,851)	—	—	(58)	(49,520)
Production	(1,210)	(489,274)	(1,508)	(450,836)	(2,685)	(292,833)
End of period	627	6,118,083	11,000	5,562,876	16,747	5,341,497
Proved Developed Reserves:						
Beginning of period	11,000	1,967,288	15,104	1,890,357	21,466	583,107
End of period	627	2,245,660	11,000	1,967,288	15,104	1,890,357
Proved Undeveloped Reserves:						
Beginning of period	—	3,595,588	1,643	3,451,140	2,146	1,699,651
End of period	—	3,872,423	—	3,595,588	1,643	3,451,140

Revisions of previous estimates. Revisions of previous estimates for oil were primarily related to changes in oil prices. Revisions of previous natural gas estimates in 2021 were primarily due to changes in natural gas prices. Revisions of previous natural gas estimates in 2020 and 2019 were primarily attributable to higher production performance from the Company's wells as compared to expected performance from proved undeveloped locations included in proved reserves in the previous year.

Extensions and discoveries. Extensions and discoveries for 2021, 2020 and 2019 were primarily comprised of proved reserve additions attributable to the wells drilled in the current year that were not classified as proved undeveloped in prior years and additional proved undeveloped reserves added from the Company's drilling program.

Acquisitions of minerals in place. The significant acquisitions of minerals in place in 2019 is primarily related to the Covey Park Acquisition.

The following table sets forth the standardized measure of discounted future net cash flows relating to proved reserves:

	As of December 31,		
	2021	2020	2019
		(In thousands)	
Cash Flows Relating to Proved Reserves:			
Future Cash Flows	$ 20,396,381	$ 9,871,616	$ 13,078,155
Future Costs:			
Production	(3,954,726)	(3,173,350)	(3,562,042)
Development and Abandonment	(2,752,603)	(2,592,520)	(3,171,351)
Future Income Taxes	(2,065,316)	(154,872)	(676,759)
Future Net Cash Flows	11,623,736	3,950,874	5,668,003
10% Discount Factor	(5,848,131)	(2,015,149)	(2,754,792)
Standardized Measure of Discounted Future Net Cash Flows	$ 5,775,605	$ 1,935,725	$ 2,913,211

The following table sets forth the changes in the standardized measure of discounted future net cash flows relating to proved reserves:

	Year Ended December 31,		
	2021	2020	2019
		(In thousands)	
Standardized Measure, Beginning of Year	$ 1,935,725	$ 2,913,211	$ 1,473,840
Net change in sales price, net of production costs	5,012,696	(1,858,026)	(716,930)
Development costs incurred during the year which were previously estimated	502,674	302,135	311,331
Revisions of quantity estimates	119,200	215,268	16,340
Accretion of discount	199,124	326,074	175,514
Changes in future development and abandonment costs	1,505	313,191	(93,476)
Changes in timing and other	(224,617)	(127,663)	180,314
Extensions and discoveries	679,418	180,624	442,099
Acquisitions of minerals in place	150,065	—	1,813,491
Sales of minerals in place	(64,032)	—	(51,070)
Sales, net of production costs	(1,567,182)	(612,194)	(580,922)
Net changes in income taxes	(968,971)	283,105	(57,320)
Standardized Measure, End of Year	$ 5,775,605	$ 1,935,725	$ 2,913,211

The standardized measure of discounted future net cash flows was determined based on the simple average of the first of month market prices for oil and natural gas for each year. Prices used in determining quantities of oil and natural gas reserves and future cash inflows from oil and natural gas reserves represent prices received at the Company's sales point. These prices have been adjusted from posted or index prices for both location and quality differences. Prices used in determining oil and natural gas reserves quantities and cash flows are as follows:

	Year Ended December 31,		
	2021	2020	2019
Crude Oil: $/barrel	$ 62.38	$ 32.88	$ 50.94
Natural Gas: $/Mcf	$ 3.33	$ 1.71	$ 2.29

Proved reserve information utilized in the preparation of the financial statements were based on estimates prepared by the Company's petroleum engineering staff in accordance with guidelines established by the Securities and Exchange Commission and the Financial Accounting Standards Board, which require that reserve reports be prepared under existing economic and operating conditions with no provision for price and cost escalation except by contractual agreement. All of the Company's reserves are located onshore in the continental United States of America. The Company retained an independent petroleum consultant to conduct an audit of the Company's 2021 reserve estimates. The purpose of this audit was to provide additional assurance on the reasonableness of internally prepared reserve estimates. The engineering firm was selected for their geographic expertise and their historical experience.

Future development and production costs are computed by estimating the expenditures to be incurred in developing and producing proved oil and gas reserves at the end of the year, based on year end costs and assuming continuation of existing economic conditions. Future income tax expenses are computed by applying the appropriate statutory tax rates to the future pre-tax net cash flows relating to proved reserves, net of the tax basis of the properties involved. The future income tax expenses give effect to permanent differences and tax credits, but do not reflect the impact of future operations.

WEBSITE

www.comstockresources.com

PRIMARY SUBSIDIARIES

Comstock Oil & Gas, LLC
Comstock Oil & Gas – Louisiana, LLC

INDEPENDENT PUBLIC ACCOUNTANTS

Ernst & Young LLP

INDEPENDENT PETROLEUM CONSULTANTS

Netherland, Sewell & Associates, Inc.

EXCHANGE LISTING

The Company's common stock is listed for trading on the New York Stock Exchange ("NYSE") under the symbol "CRK".

TRANSFER AGENT AND REGISTRAR

For stock certificate transfers, changes of address or lost stock certificates, please contact:
American Stock Transfer & Trust Company
6201 15th Avenue
Brooklyn, New York 11219
(800) 937-5449
help@astfinancial.com

INVESTOR RELATIONS

Requests for additional information should be directed to:
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CORPORATE GOVERNANCE AND EXECUTIVE CERTIFICATIONS

Our Corporate Governance Guidelines are available by selecting Investor Info on our web site at www.comstockresources.com. We have included as exhibits to our 2021 Annual Report on Form 10-K filed with the Securities and Exchange Commission, certificates of our chief executive officer and chief financial officer regarding the quality of our public disclosure. We have also submitted to the NYSE a certificate of our chief executive officer certifying that he is not aware of any violation by the company of the NYSE corporate governance listing standards.

BOARD OF DIRECTORS

M. Jay Allison [1]
Jim L. Turner [2]
Roland O. Burns
Elizabeth B. Davis
Morris E. Foster

[1] Chairman of the Board of Directors
[2] Lead Independent Director

MANAGEMENT

M. Jay Allison
Chief Executive Officer and Chairman of the Board of Directors

Roland O. Burns
President, Chief Financial Officer, Secretary and Director

Daniel S. Harrison
Chief Operating Officer

David J. Terry
Senior Vice President of Corporate Development

Patrick H. McGough
Vice President of Operations

Ronald E. Mills
Vice President of Finance and Investor Relations

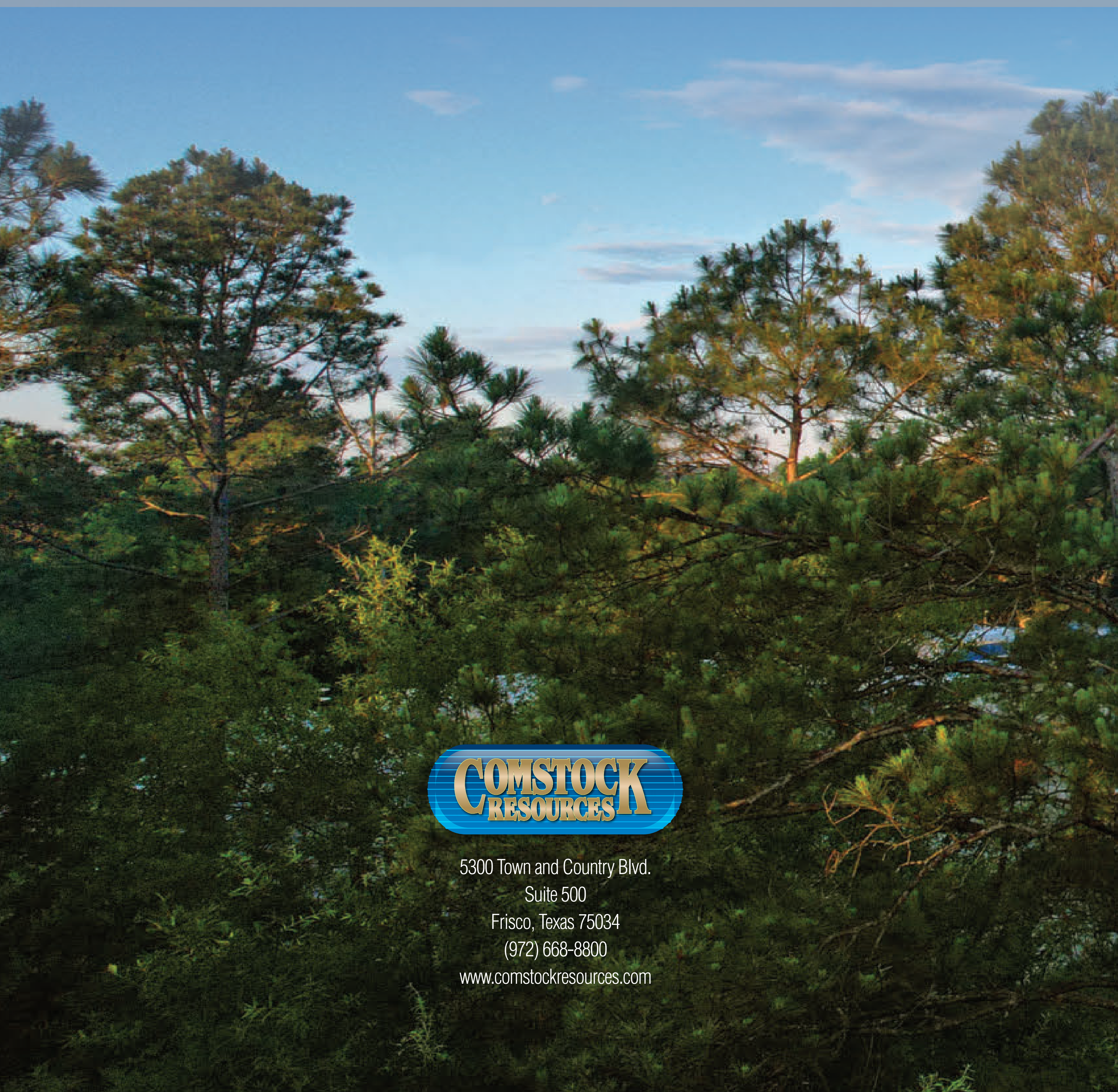
Daniel K. Presley
Vice President of Accounting, Controller and Treasurer

LaRae L. Sanders
Vice President of Land

Whitney H. Ward
Vice President of Marketing

Brian C. Claunch
Vice President of Financial Reporting

25 YEARS CRK LISTED NYSE



COMSTOCK RESOURCES

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