As filed with the Securities and Exchange Commission on August 12, 2024

Registration No. 333-268469

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

AMENDMENT NO. 11
TO

FORM S-1

REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933

BKV CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**1311**	**85-0886382**
(State or other jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification Number)

1200 17th Street, Suite 2100
Denver, Colorado 80202
(720) 375-9680

(Address, including zip code, and telephone number, including area code, of registrant's principal executive offices)

Christopher P. Kalnin
Chief Executive Officer
BKV Corporation
1200 17th Street, Suite 2100
Denver, Colorado 80202
(720) 375-9680

(Name, address, including zip code, and telephone number, including area code, of agent for service)

Copies to:

Samantha H. Crispin **M. Preston Bernhisel** **Adorys Velazquez** **Baker Botts L.L.P.** **2001 Ross Avenue, Suite 900** **Dallas, Texas 75201** **(214) 953-6500**	**Michael Chambers** **Monica E. White** **Latham & Watkins LLP** **811 Main Street, Suite 3700** **Houston, Texas 77002** **(713) 546-5400**

Approximate date of commencement of proposed sale to the public:
As soon as practicable after the effective date of this registration statement.

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box. ☐

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, please check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ☐

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ☐

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ☐

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

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 7(a)(2)(B) of the Securities Act. ☒

The registrant hereby amends this registration statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this registration statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933, as amended, or until the registration statement shall become effective on such date as the Securities and Exchange Commission, acting pursuant to said Section 8(a), may determine.

SUBJECT TO COMPLETION, DATED , 2024

PRELIMINARY PROSPECTUS

Shares

BKV Corporation

Common Stock

This is the initial public offering of common stock of BKV Corporation, a Delaware corporation. Prior to this offering, there has been no public market for our common stock. We anticipate that the initial public offering price will be between $ and $ per share. We have applied to list our common stock on the New York Stock Exchange ("NYSE") under the symbol "BKV."

We have granted the underwriters a 30-day option to purchase up to additional shares from us at the initial public offering price, less the underwriting discounts and commissions.

We are an "emerging growth company" as the term is used in the Jumpstart Our Business Startups Act of 2012 and, as such, have elected to comply with certain reduced public company reporting requirements. See "*Prospectus Summary—Implications of Being an Emerging Growth Company.* "

Upon completion of this offering, affiliates of Banpu Public Company Limited will beneficially own approximately % of the voting power of the outstanding shares of our common stock. As a result, we will be a "controlled company" within the meaning of the NYSE rules. See "*Management—Controlled Company.*"

Investing in our common stock involves risks, including those described under "*Risk Factors*" beginning on page 41 of this prospectus.

	Price to Public	Underwriting Discounts and Commissions(1)	Proceeds to BKV Corporation
Per Share	$	$	$
Total	$	$	$

(1) The underwriters will also be reimbursed for certain expenses incurred in this offering. See "*Underwriting*" for additional information regarding underwriting compensation.

Neither the Securities and Exchange Commission nor any securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

The underwriters expect to deliver the shares of our common stock on or about , 2024.

Joint Book-Running Managers

Citigroup **Barclays**

Evercore ISI **Jefferies**

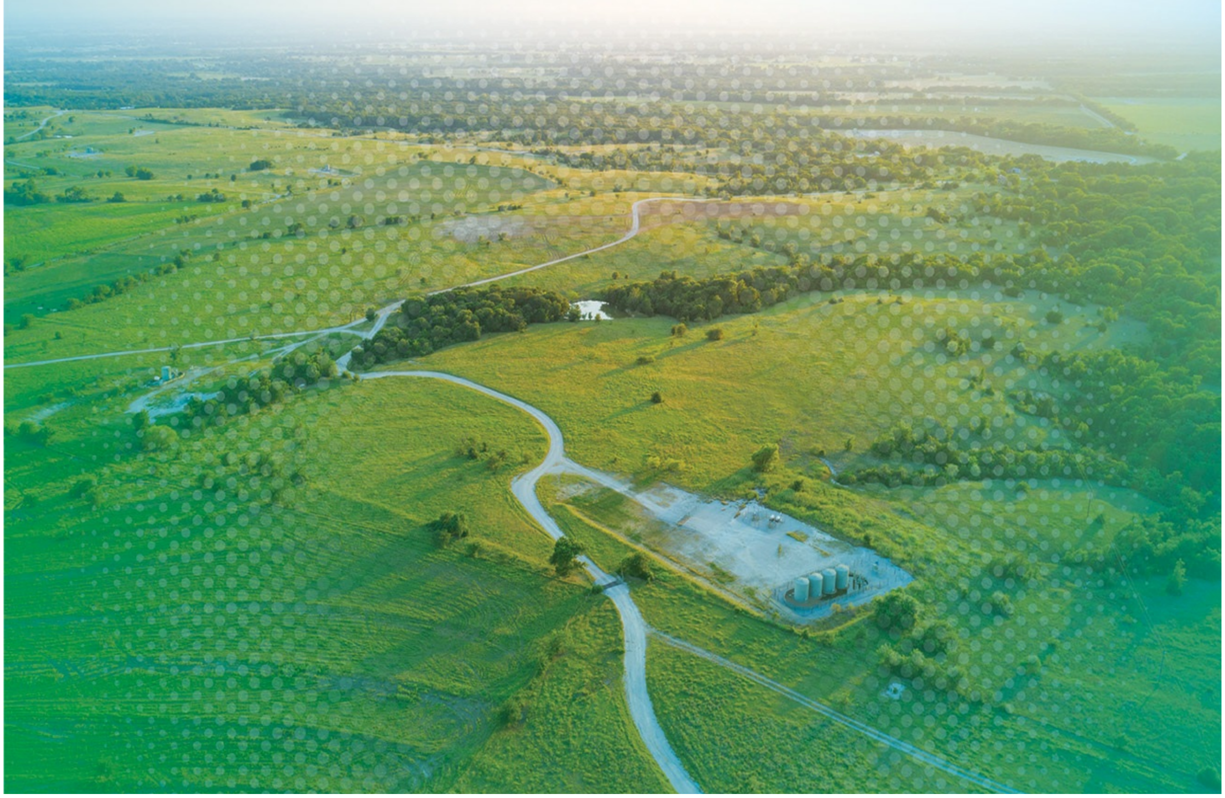
Co-Managers

TPH&Co. **Susquehanna Financial Group, LLLP**

The date of this prospectus is , 2024.

The information in this preliminary prospectus is not complete and may be changed. These securities may not be sold until the re statement filed with the Securities and Exchange Commission is effective. This preliminary prospectus is not an offer to sell these securit is not soliciting an offer to buy these securities in any jurisdiction where the offer or sale is not permitted.

Straight. Forward. Energy.



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Dealer Prospectus Delivery Obligation

Through and including , 2024 (the 25th day after the date of this prospectus), all dealers that effect transactions in our common stock, whether or not participating in this offering, may be required to deliver a prospectus. This delivery requirement is in addition to a dealer's obligation to deliver a prospectus when acting as an underwriter and with respect to unsold allotments or subscriptions.

You should rely only on the information contained in this prospectus or in any free writing prospectus that we authorize to be distributed to you. We and the underwriters have not authorized anyone to provide you with any information other than that contained in this prospectus or in any free writing prospectus prepared by or on behalf of us or to which we have referred you, and neither we, nor the underwriters take responsibility for any other information others may give you. We are offering to sell, and seeking offers to buy, shares of our common stock only in jurisdictions where such offers and sales are permitted. The information in this prospectus or any free writing prospectus is accurate only as of its date, regardless of its time of delivery or the time of any sale of shares of our common stock. Our business, financial condition, results of operations and prospects may have changed since that date.

Industry and Market Data

In this prospectus, we present certain market and industry data. This information is based on third-party sources which we believe to be reliable as of their respective dates. Neither we nor the underwriters have independently verified any third-party information. Some data is also based on our good faith estimates. Expectations of our and our industry's future performance are necessarily subject to a high degree of uncertainty and risk due to a variety of factors, including those described in "*Risk Factors*." These and other factors could cause future performance to differ materially from our expectations. See "*Cautionary Statement Regarding Forward-Looking Statements*."

Reverse Stock Split

On October 30, 2023, we completed a one-for-two reverse stock split. As a result of the reverse stock split, every two shares of our outstanding common stock were combined into and now represent one share of common stock, and fractional shares were paid out in cash. All shares of common stock issuable upon exercise of equity awards, as well as the applicable exercisable prices and weighted average fair value of the equity awards, and per share amounts contained throughout this prospectus have been retroactively adjusted.

Presentation of Financial, Reserves and Operating Data

Unless indicated otherwise, the historical financial information presented in this prospectus is that of BKV Corporation and its consolidated subsidiaries as of December 31, 2023 or June 30, 2024, as applicable. The historical natural gas, NGL and oil reserves data presented in this prospectus as of December 31, 2023, 2022 and 2021 are based on the reserves reports prepared by Ryder Scott Company, L.P., independent petroleum engineers.

In addition, unless indicated otherwise, the operational data presented in this prospectus is that of BKV Corporation and its consolidated subsidiaries on a consolidated basis as of and for the periods presented.

As a result of our acquisition transactions in recent years, our historical operating, financial and reserves data may not be comparable between periods presented in this prospectus. See "*Management's Discussion and Analysis of Financial Condition and Results of Operations — Factors that Affect Comparability of Our Results of Operations*."

Trademarks and Trade Names

We own or have rights to various trademarks, service marks and trade names that we use in connection with the operation of our business. This prospectus may also contain trademarks, service marks and trade names of third parties, which are the property of their respective owners. Our use or display of third parties' trademarks, service marks, trade names or products in this prospectus is not intended to, and does not imply a relationship with, or endorsement or sponsorship by us. Solely for convenience, the trademarks, service marks and trade names referred to in this prospectus may appear without the ®, ™ or SM symbols, but such references are not intended to indicate, in any way, that we will not assert, to the fullest extent under applicable law, our rights or the rights of the applicable licensor to these trademarks, service marks and trade names.

Rounding and Percentages

The financial information and certain other information presented in this prospectus have been rounded to the nearest whole number or the nearest decimal. Therefore, the sum of the numbers in a column may not conform exactly to the total figure given for that column in certain tables in this prospectus. In addition, certain percentages presented in this prospectus reflect calculations based upon the underlying information prior to rounding and, accordingly, may not conform exactly to the percentages that would be derived if the relevant calculations were based upon the rounded numbers or may not sum due to rounding.

Other Considerations

This prospectus contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. See "*Risk Factors*" and "*Cautionary Statement Regarding Forward-Looking Statements*" for additional information regarding these risks.

You should read this prospectus and any written communication prepared by us or on our behalf in connection with this offering, together with the additional information described in the section of this prospectus titled "*Where You Can Find More Information*." We have not authorized anyone to provide you with information or to make any representation in connection with this offering other than those contained herein. If anyone makes any recommendation or gives any information or representation regarding this offering, you should not rely on that recommendation, information or representation as having been authorized by us, the underwriters or any other person on our behalf. The information contained in this prospectus is accurate only as of the date of which it is shown, or if no date is otherwise indicated, the date of this prospectus, regardless of the time of delivery of this prospectus or of any sale of our shares of common stock. We are offering to sell, and seeking offers to buy, shares of common stock only in jurisdictions where offers and sales are permitted. Our business, financial condition, results of operations and prospects may have changed since that date. Information contained on our website is not part of this prospectus.

No action is being taken in any jurisdiction outside the United States to permit a public offering of shares of common stock or possession or distribution of this prospectus in that jurisdiction. Persons who come into possession of this prospectus in jurisdictions outside the United States are required to inform themselves about and to observe any restrictions as to this offering and the distribution of this prospectus applicable to that jurisdiction.

Glossary of Oil and Natural Gas Terms

The following are abbreviations and definitions of certain terms used in this prospectus, which are commonly used in the oil and natural gas industry:

"***Bbl***" refers to one stock tank barrel, of 42 U.S. gallons liquid volume, used in this prospectus in reference to crude oil or other liquid hydrocarbons.

"***Bcf***" refers to one billion cubic feet of natural gas or CO_2.

"***Bcfe***" refers to one billion cubic feet of natural gas equivalent.

"***Btu***" refers to British thermal unit, which is the heat required to raise the temperature of one pound of liquid water by one degree Fahrenheit.

"***CCUS***" refers to carbon capture, utilization and sequestration.

"CO_2" refers to carbon dioxide.

"CO_2e" refers to carbon dioxide equivalent.

"***developed acreage***" refers to the number of acres that are allocated or assignable to productive wells or wells capable of production.

"***developed reserves***" are reserves of any category that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well or (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

"***dry hole***" refers to 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.

"***Effective NRI***" refers to our share of leasehold ownership after all burdens, such as royalty and overriding royalty interests, have been deducted from the working interest, weighted by our net acres owned in the Barnett from the assets acquired in the Devon Barnett Acquisition and the Exxon Barnett Acquisition.

"***gross acres***," "***gross acreage***" or "***gross wells***" refers to the total acres, acreage or wells, as the case may be, in which a working interest is owned.

"***IPIECA***" refers to the International Petroleum Industry Environmental Conservation Association.

"***lean gas***" refers to natural gas that contains a few or no liquefiable liquid hydrocarbons.

"***LNG***" refers to liquefied natural gas.

"***Maintenance Reinvestment Rate***" for any period refers to the maximum rate of our total capital expenditures accrued for the development of natural gas properties (excluding leasehold costs and acquisitions) for such period as a percentage of Adjusted EBITDAX for the same period that is necessary to hold our production for such period flat.

"***MBbls***" refers to one thousand barrels of crude oil or other liquid hydrocarbons.

"***Mcf***" refers to one thousand cubic feet.

"***Mcf/d***" refers to one thousand cubic feet per day.

"***Mcfe***" refers to one thousand cubic feet of natural gas equivalent.

"***MMBtu***" refers to one million Btus.

"***MMcf***" refers to one million cubic feet.

"***MMcf/d***" refers to one million cubic feet per day.

"***MMcfe***" refers to one million cubic feet of natural gas equivalent, calculated by converting barrels of crude oil or other liquid hydrocarbons to natural gas at a ratio of one Bbl to six Mcf of natural gas. This is an energy content correlation and does not reflect a value or price relationship between the commodities.

"***MMcfe/d***" refers to one million cubic feet of natural gas equivalent per day.

"***Mtpa***" refers to million metric tons of LNG per year.

"***Mtpy***" refers to million metric tons per year.

"***net acres***" refers to the percentage of total acres an owner has out of a particular number of acres, or a specified tract. For example, an owner who has 50% interest in 100 acres owns 50 net acres.

"***net operated development well***" refers to a gross operated development well that has been drilled, proportionately reduced by our working interest in such well.

"***NGL***" refers to natural gas liquids.

"***NYMEX***" refers to the New York Mercantile Exchange.

"***OPEC***" refers to the Organization of the Petroleum Exporting Countries.

"***proved developed non-producing reserves***" refers to proved developed reserves expected to be recovered from (i) completion intervals that are open at the time of the estimate but which have not yet started producing, (ii) wells which were shut-in for market conditions or pipeline connections, (iii) wells not capable of production for mechanical reasons or (iv) zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves, in each case, which production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well. While not a requirement for disclosure under SEC regulations, proved developed non-producing reserves have been sub-classified and calculated by Ryder Scott in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

"***proved developed producing reserves***" or "***PDP reserves***" refers to quantities of proved developed reserves expected to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation. While not a requirement for disclosure under SEC regulations, PDP reserves have been sub-classified and calculated by Ryder Scott in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

"***proved reserves***" refers to quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible — from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations — prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons ("LKH") as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined an HKO elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (a) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (b) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

"***PUD reserves***" refers to proved undeveloped reserves.

"***rich gas***" refers to natural gas containing heavier hydrocarbons than a lean gas.

"***Scope 1 emissions***" refers to direct GHG emissions that occur from sources that are controlled or owned by an organization.

"***Scope 2 emissions***" refers to indirect GHG emissions associated with the purchase of electricity, steam, heat or cooling.

"***Scope 3 emissions***" refers to GHG emissions that result from the end use of an organization's products, as estimated per Category 11 (Use of Sold Product), as well as emissions from other business activities from assets not owned or controlled by the organization but that the organization indirectly impacts in its value chain.

"***Tcfe***" refers to one trillion cubic feet of natural gas equivalent.

"***undeveloped acreage***" refers to acreage under lease on which wells have not been drilled or completed such that there is not production of commercial quantities of hydrocarbons.

"***undeveloped reserves***" are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time. Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology establishing reasonable certainty.

"***Upstream Reinvestment Rate***" for any period refers to our total capital expenditures accrued for the development of natural gas properties (excluding leasehold costs and acquisitions) for such period as a percentage of Adjusted EBITDAX for the same period.

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

Commonly Used Defined Terms

As used in this prospectus, unless the context indicates or otherwise requires, the terms listed below have the following meanings:

"***Banpu***" refers to our sponsor, Banpu Public Company Limited, a public company listed on the Stock Exchange of Thailand and the ultimate parent company of BKV Corporation, BNAC, Banpu Power and BPPUS.

"***Banpu Power***" refers to Banpu Power Public Company Limited, a public company listed on the Stock Exchange of Thailand. Banpu owns approximately 78.66% of Banpu Power as of June 30, 2024.

"***Barnett***" refers to the Barnett Shale in the Fort Worth Basin of Texas.

"***BKV Barnett***" refers to BKV Barnett LLC, a Delaware limited liability company and wholly owned subsidiary of BKV Corporation.

"***BKV Chaffee***" refers to BKV Chaffee Corners, LLC, a Delaware limited liability company and former wholly owned subsidiary of BKV Corporation.

"***BKV Chelsea***" refers to BKV Chelsea, LLC, a Delaware limited liability company and wholly owned subsidiary of BKV Corporation.

"***BKV dCarbon Ventures***" refers to BKV dCarbon Ventures, LLC, a Delaware limited liability company and the CCUS business of BKV Corporation.

"***BKV Midstream***" refers to BKV Midstream, LLC, a Delaware limited liability company and wholly owned subsidiary of BKV Corporation.

"***BKV O&G***" refers to BKV Oil and Gas Capital Partners, L.P., a Delaware limited partnership and wholly owned subsidiary of BKV Corporation, which was dissolved on September 19, 2022, on which date all ownership interests in subsidiaries of BKV O&G were assigned to BKV Corporation.

"***BKV Operating***" refers to BKV Operating, LLC, a Delaware limited liability company and wholly owned subsidiary of BKV Corporation.

"***BKV Upstream Midstream***" refers to BKV Upstream Midstream, LLC, a Delaware limited liability company and wholly owned subsidiary of BKV Corporation.

"***BKV-BPP Cotton Cove***" or "***BKV-BPP Cotton Cove Joint Venture***" refers to BKV-BPP Cotton Cove, LLC, a Delaware limited liability company and the joint venture between BKV dCarbon Ventures and BPPUS, in which we own an indirect 51% interest.

"***BKV-BPP Power***" or "***BKV-BPP Power Joint Venture***" refers to BKV-BPP Power LLC, a Delaware limited liability company and the joint venture between BKV Corporation and BPPUS, in which we own a 50% interest.

"***BKV-BPP Retail***" refers to BKV-BPP Retail, LLC, a Delaware limited liability company and wholly owned subsidiary of the BKV-BPP Power Joint Venture.

"***BKVerde***" refers to BKVerde, LLC, a Delaware limited liability company and wholly owned subsidiary of BKV dCarbon Ventures.

"***BNAC***" refers to Banpu North America Corporation, a subsidiary of Banpu, our sponsor, and the majority stockholder of BKV Corporation.

"***BPPUS***" refers to Banpu Power US Corporation, a wholly owned subsidiary of Banpu Power and the owner of a 50% interest in the BKV-BPP Power Joint Venture and a 49% interest in the BKV-BPP Cotton Cove Joint Venture.

"***bylaws***" refers to the second amended and restated bylaws of BKV Corporation to be adopted in connection with the consummation of this offering.

"***Carbon Sequestered Gas***" refers to a Scope 1, 2 and 3 carbon neutral natural gas product.

"***certificate of incorporation***" refers to the second amended and restated certificate of incorporation of BKV Corporation to be adopted in connection with the consummation of this offering.

"***Code***" means the Internal Revenue Code of 1986, as amended.

"***Data Lake***" refers to a centralized cloud, large data technology that stores all company data and enables dashboards, visualizations, and analytics from a variety of systems and inputs.

"***Devon Barnett Acquisition***" refers to our acquisition of more than 289,000 net acres, 3,850 producing operated wells and related upstream assets in the Barnett from Devon Energy Corporation, which closed in October 2020.

"***ERCOT***" refers to the Electric Reliability Council of Texas.

"***ESG***" refers to environmental, social and governance.

"***Exxon Barnett Acquisition***" refers to our acquisition of approximately 165,000 net acres, 2,100 operated wells and related natural gas upstream, midstream and other assets in the Barnett from XTO Energy, Inc. and Barnett Gathering LLC, subsidiaries of Exxon Mobil Corporation, which closed on June 30, 2022.

"***FID***" refers to final investment decision.

"***GAAP***" refers to generally accepted accounting principles in the United States.

"***GHG***" refers to greenhouse gases.

"***governing documents***" refers to our certificate of incorporation and our bylaws.

"***High West***" refers to High West Sequestration, LLC, a Louisiana limited liability company and wholly owned subsidiary of BKV dCarbon Ventures.

"***HRCO***" refers to a contract for the financial purchase and sale of power based on a floating price of natural gas at a predetermined location using a predetermined conversion factor, or heat rate, required to turn the fuel input into electricity.

"***Kalnin Ventures***" refers to Kalnin Ventures LLC, a Colorado limited liability company and wholly owned subsidiary of BKV Corporation.

"***NEPA***" refers to the Marcellus Shale in the Appalachian Basin of Northeast Pennsylvania.

"***net zero***" refers to the full elimination and/or offset of Scope 1, Scope 2 and/or Scope 3 emissions, as applicable, from our owned and operated upstream businesses.

"***NGP***" refers to natural gas processing.

"***RBL Borrower***" refers to BKV Upstream Midstream, LLC, a wholly owned subsidiary of BKV Corporation.

"***RBL Credit Agreement***" refers to that certain reserve-based lending agreement dated as of June 11, 2024, among BKV Corporation, the RBL Borrower, Citibank, N.A., as administrative agent, and the financial institutions party thereto.

"***Responsibly Sourced Gas***" or "***RSG***" refers to natural gas produced from a well which has gone through Project Canary's TrustWell environmental assessment and verification process and has a current TrustWell rating.

"***Ryder Scott***" refers to Ryder Scott Company, L.P., independent petroleum engineers.

"***SREC***" refers to Solar Renewable Energy Credit, which represents a form of environmental attribute associated with solar energy generation, which can be marketed for financial gain to improve project economics or retired to offset the SREC owner's Scope 2 emissions. For every 1,000 kilowatt-hours of electricity produced by an eligible solar facility, one renewable energy credit and one compliance premium is awarded. The combination of a renewable energy credit and a compliance premium is known as an SREC. For a solar facility to be credited with that SREC, the system must be certified and registered by state agencies.

"***Temple I***" refers to the combined gas turbine and steam turbine power plant located in Temple, Texas and owned by the BKV-BPP Power Joint Venture.

"***Temple II***" refers to a second combined gas turbine and steam turbine power plant located in Temple, Texas, which power plant sits on the same site as Temple I and is owned by the BKV-BPP Power Joint Venture.

"***Temple Plants***" refers to Temple I and Temple II, collectively.

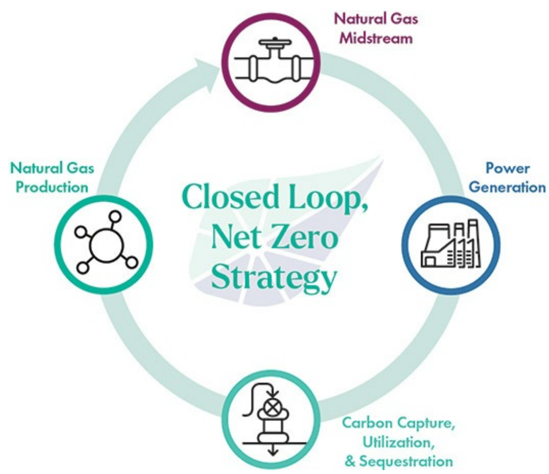
PROSPECTUS SUMMARY

This summary highlights certain information about us and this offering contained elsewhere in this prospectus, but it is not complete and does not contain all of the information you should consider before making an investment decision. In addition to this summary, you should read this entire prospectus carefully, including the sections titled "Risk Factors," "— Summary Historical Financial Information," "Management's Discussion and Analysis of Financial Condition and Results of Operations," and our historical consolidated financial statements and the related notes thereto included elsewhere in this prospectus, before making an investment decision. This summary contains forward-looking statements that involve risks and uncertainties. See "Cautionary Statement Regarding Forward-Looking Statements." References in this prospectus to "BKV," the "Company," "we," "us," "our" and like terms are to BKV Corporation, a Delaware corporation, and its wholly owned subsidiaries, unless the context otherwise requires or we otherwise state.

Our Company

Overview

We are a forward thinking, growth driven energy company focused on creating value for our stockholders through the organic development of our properties as well as accretive acquisitions. Our core business is to produce natural gas from our owned and operated upstream businesses, which are supported by our four business lines: natural gas production; natural gas gathering, processing and transportation (our "natural gas midstream business"); power generation; and carbon capture, utilization and sequestration ("CCUS"). We expect our owned and operated upstream and natural gas midstream businesses to achieve net zero Scope 1 and Scope 2 emissions by the early 2030s, and net zero Scope 1, 2 and 3 emissions by the late 2030s. We maintain a "closed-loop" approach to our net zero emissions goal through the operation of our four business lines. We are committed to vertically integrating portions of our business to reduce costs and improve overall commercial optimization of the full value chain. For instance, in the Barnett, our natural gas production is gathered and transported in part through our midstream systems and we commenced sequestration operations at our first CCUS project in November 2023. We expect our second CCUS project to commence sequestration activities in the first half of 2026 and are evaluating a robust backlog of actionable CCUS opportunities. We believe that our differentiated business model, net zero emissions focus, highly experienced management team and technology-driven approach to operating our business will enable us to create stockholder value.



We understand the impact climate change has on our community, the world and future generations, which is why addressing these impacts in how energy is produced is a top priority. In particular, it is one of our core values, “Be One BKV,” to create a unified team with a shared vision to achieve our emission reduction and energy impact goals.

Overview of BKV Assets

Natural Gas

	Net Production (MMcfe/d)	SEC 1P Reserves (Tcfe)	Producing Wells[1]	Net Acres
	Year Ended December 2023	As of December 2023	As of December 2023	As of December 2023
Barnett	718	3.7	6,614	460,000
NEPA	142	0.4	414	37,000
Total	860	4.1	7,028	497,000

Operated Midstream

	As of December 2023 Throughput (MMcf/d)	Pipeline Miles	Midstream Compressors
Barnett	233	778	65

Power

	Location	Heat Rate Btu/kWh	Capacity MW+
Temple I	Bell County, TX	6,904	752
Temple II	Bell County, TX	6,950	747

CCUS

Projects in Operation	Status	Initiation of Sequestration Operations	Forecasted Annual Sequestration Volumes (Mtpy CO_2e)[4]
Barnett Zero	Operating	November 2023	0.18
Potential Projects	**Status[2]**	**Forecasted Initiation of Sequestration Operations[3]**	**Forecasted Annual Sequestration Volumes (Mtpy CO_2e)[4]**
Cotton Cove	FID	1H 2026	0.04
8 NGP Projects	Pre-FID	2025-2029	2.68
3 Industrial Projects	Pre-FID	2026-2027	11.15
4 Ethanol Projects	Pre-FID	2027-2029	2.56

(1) Includes producing wells in which BKV has an ORRI or Non-Operated Interest.
(2) We have not secured external financing, reached FID or entered into the definitive agreements necessary to execute any of the pre-FID projects identified above.
(3) Our projected timeline for commencement of sequestration operations at the Cotton Cove Project and all of the pre-FID projects identified above depends in part on our ability to fund the capital requirements for these potential projects through external funding and revenues from our upstream business, as well as a regulatory environment that is favorable to our projects and their development. See *Risk Factors—Risks Related to our CCUS Business.*
(4) We may not receive 100% of the environmental attributes associated with CCUS projects funded in whole or in part by third parties, and, in such cases, we expect to have the right to purchase such environmental attributes BKV would not otherwise receive. Ultimately, we will be able to apply only such portion of the sequestered emissions to offset our own GHG emissions that corresponds to the percentage of environmental attributes BKV receives or purchases.

Our Operations

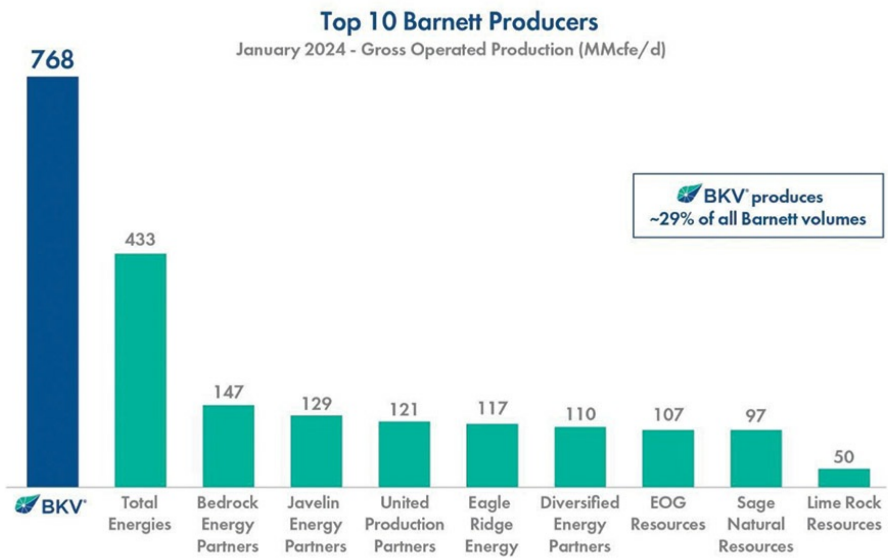
Natural Gas Production

We are engaged in the acquisition, operation and development of natural gas and NGL properties primarily located in the Barnett Shale in the Fort Worth Basin of Texas (the "Barnett") and in the Marcellus Shale in the Appalachian Basin of Northeastern Pennsylvania ("NEPA"). Our upstream assets are the core of our business and provide us with substantial Adjusted Free Cash Flow, which we expect will be sufficient to fund our upstream, midstream and power capital expenditure program while maintaining a conservative balance sheet. We have a balanced portfolio of low decline producing properties and undeveloped inventory, primarily in the Barnett. Additionally, our focus on operational efficiencies, access to BKV-owned and third-party midstream systems, and proximity to natural gas demand markets along the Gulf Coast and Northeast corridor allow us to generate high margins.

As of June 30, 2024, our total acreage position was approximately 479,000 net acres, 99% of which was held by production. For the six months ended June 30, 2024, our net daily production averaged 807.6 MMcfe/d, consisting of approximately 80% natural gas and approximately 20% NGLs. As of December 31, 2023, our total proved reserves of 4,094 Bcfe had an estimated 8.1% year-over-year average base decline rate over the next 10 years. As of December 31, 2023, we had more than 15 years of core development inventory, with attractive returns, based on a 1 to 1.5 rigs per year pace, including 535 gross drilling locations, of which 99 are proved locations, and 2,097 gross refracture ("refrac") candidates, of which 501 are proved locations. For a discussion of how we identify drilling locations and refrac candidates, please see "*Business — Our Operations — Natural Gas Production — Determination of Identified Drilling and Refracture Locations*." Based on current commodity prices, the capital investment required to hold production flat year-over-year is equal to less than approximately 60% of our Adjusted EBITDAX for the 2023 fiscal year. Adjusted EBITDAX is not a financial measure calculated in accordance with GAAP. See "*— Summary Historical Financial Information — Non-GAAP Financial Measures*" for a description of this measure and a reconciliation to the most directly comparable GAAP measure.

We entered the Barnett in October 2020 with our acquisition of more than 289,000 net acres and 3,850 producing operated wells and related upstream assets (the "2020 Barnett Assets") from Devon Energy Corporation ("Devon Energy"). On June 30, 2022, we further scaled our Barnett position by acquiring approximately 165,000 net acres, 2,100 operated wells and related upstream, midstream and other assets in the Exxon Barnett Acquisition. As of June 30, 2024, our Barnett acreage position was approximately 460,000 net acres, which is approximately 99% held by production. Our average daily Barnett production of approximately 682.5 MMcfe/d for the six months ended June 30, 2024 consisted of approximately 76% natural gas and approximately 24% NGLs. We had an average working interest in our operated wells in the Barnett of approximately 96.9% as of December 31, 2023 and an Effective NRI in the Barnett of approximately 80.2%.

We are the largest natural gas producer by gross operated volume in the Barnett. Based on information published by the Texas Railroad Commission ("TRRC"), the chart below illustrates our gross operated production volumes in the Barnett as of January 2024, which represent approximately 29% of the total Barnett production, and nearly double than that of the next largest producer in the Barnett for the month of January 2024.



We entered NEPA in 2016 and have subsequently scaled our position through 12 acquisitions. As of June 30, 2024, our acreage position was approximately 19,480 net acres, which is approximately 97.5% held by production. Our average net daily production of 125.2 MMcfe/d for the six months ended June 30, 2024 consisted entirely of natural gas. We had an average working interest in our operated wells in NEPA of 89.4%, as of December 31, 2023.

On June 14, 2024, we sold our wholly owned subsidiary, BKV Chaffee, which owned a non-operated interest in approximately 9,800 net acres and 116 gross (24.2 net) wells and approximately 122 Bcfe of proved reserves in NEPA, as well as our interest in the Repsol Oil & Gas operated midstream system, for a purchase price of $106.7 million, subject to adjustment. On June 28, 2024, our wholly owned subsidiary, BKV Chelsea, sold certain of its non-operated upstream assets, including its interest in approximately 6,800 net acres and 214 gross (15.4 net) wells and approximately 35 Bcfe of proved reserves in NEPA for a purchase price of $25.0 million, subject to adjustment.

In February 2023, we re-certified most of our production under the TrustWell environmental assessment program of Project Canary, an environmental certification and ESG data company. We achieved a Gold rating from Project Canary, the second highest rating a company can receive for its production, qualifying the certified portion of our natural gas production as Responsibly Sourced Gas (“RSG”). As part of its environmental assessment, Project Canary analyzes and certifies our production on a well by well basis. As of June 30, 2024, approximately 70% of our NEPA production and approximately 45% of our Barnett production was re-certified. We intend to continue an environmental assessment of substantially all of our existing production. In addition, we intend to advance the market for our produced gas beyond RSG and its current certification towards “Carbon Sequestered Gas”, a Scope 1, 2 and 3 carbon neutral natural gas product. We expect that production of Carbon Sequestered Gas will be achieved by bundling RSG with carbon credits sufficient to offset the estimated emissions associated with the production, gathering and boosting of such RSG, as well as the estimated emissions from its transmission, distribution (if applicable) and ultimate combustion, with the quantified emissions and the requisite volume of CCUS offsets being third-party certified. We have an agreement with a third party to establish the blockchain ledger and tokens; however, this process is dependent upon the development of the necessary technology by such third party. In addition, we expect to utilize the blockchain ledger and tokens with the American Carbon Registry, once that registry has been established. The carbon credits included in our Carbon Sequestered Gas will be generated by our CCUS projects, as described below in “— *Path to Net Zero Emissions*” and retired against our Scope 1 and/or Scope 3 emissions. We believe Carbon Sequestered Gas could potentially provide a decarbonized, certified and qualified fuel and retired credits bundle that is a differentiated and premium product.

In August 2023, BKV entered into a contract with ENGIE Energy Marketing NA, Inc, a subsidiary of global energy utility ENGIE S.A. ("ENGIE"), for the sale and purchase of up to 10,000 MMBtu/d of our Carbon Sequestered Gas. Additionally, in March 2024, BKV entered into a contract with Kiewit Infrastructure South Co., a subsidiary of Kiewit Corporation ("Kiewit"), for the sale and purchase of up to 100 MMBtu/d of our Carbon Sequestered Gas. The carbon credits included in our Carbon Sequestered Gas will be generated by our CCUS projects and will be third-party verified. Subject to completion of our certification process with the American Carbon Registry (see "— *Carbon Capture, Utilization and Sequestration*" below), we expect to begin delivery of Carbon Sequestered Gas by the end of 2024.

Natural Gas Midstream

Through our ownership in midstream systems, we are engaged in the gathering, processing and transportation of natural gas (which we refer to as our natural gas midstream business) that supports our upstream assets and third-party producers in the Barnett and NEPA. Our midstream assets improve our overall corporate returns by enhancing our margins and lowering our break-even operating costs while allowing us to manage the timing, development and optimization of production of our upstream assets. In the Barnett, during the six months ended June 30, 2024, approximately 193 MMcf/d of our gross production (approximately 22% of our total gross Barnett production) was gathered and processed by our owned Barnett midstream system, which includes approximately 778 miles of gathering pipeline, 65 midstream compressors and one amine processing unit. Additionally, our owned Barnett midstream system has over 200 MMcf/d in unutilized pipeline and processing capacity, providing room to increase throughput (from our own production and for third-party volumes) while maintaining optimal operating pressure with limited additional capital investment required. We also believe we have ample dedicated capacity on third party midstream systems for our expected production and future development. We own and operate approximately 16 miles of natural gas gathering pipelines, 14 miles of freshwater distribution pipelines and six gas compression units in NEPA. As part of our sale of BKV Chaffee, we sold our minority non-operated ownership interest in a Repsol Oil & Gas operated midstream system in NEPA on June 14, 2024.

Power Generation

We have a 50% ownership interest in the BKV-BPP Power Joint Venture, which owns the Temple Plants, modern combined cycle gas and steam turbine power plants located in the Electric Reliability Council of Texas ("ERCOT") North Zone in Temple, Texas. The remaining 50% interest is owned by BPPUS, a wholly owned subsidiary of Banpu Power and an affiliate of our sponsor, Banpu. Temple I and Temple II have annual average power generation capacities of 752 MW and 747 MW, respectively, and each power plant delivers power to customers on the ERCOT power network in Texas. Temple I and Temple II have baseload design heat rates of approximately 6,904 Btu/kWh and 6,950 Btu/kWh, respectively, which are below the ERCOT Combined Cycle Gas Turbines ("CCGT") average. The modern technology utilized at the Temple Plants enables them to respond to rapidly changing market signals in real time, ensuring the highest operational readiness during the time when electricity consumption peaks (in winter and summer), making the power plants well-suited to serve the various needs of the ERCOT market. We continue to explore potential additional acquisitions to expand our power generation business. We expect our power generation assets will be synergistic with our base upstream business and we leverage our existing organization to provide marketing, engineering, finance, accounting and other administrative services to the BKV-BPP Power Joint Venture for an annual fee plus expenses.

In addition, after receiving the necessary approvals from the Public Utility Commission of Texas (the "PUCT") and ERCOT, the BKV-BPP Power Joint Venture recently launched a retail marketing business to sell electricity to commercial, industrial, and residential retail customers in Texas through its wholly owned subsidiary, BKV-BPP Retail, LLC ("BKV-BPP Retail"), under the brand name BKV Energy. Since its official launch in February 2023, BKV Energy has built a portfolio of over 57,000 customers and is licensed to serve throughout the deregulated portions of Texas.

Carbon Capture, Utilization and Sequestration

Through our CCUS business, we aim to reduce man-made GHG emissions to the atmosphere by capturing CO_2 emitted in connection with natural gas activities, whether from our own operations or third- party operations, as well as from other energy and industrial sources. Our process involves capturing CO_2 before it is released into the atmosphere and then compressing the captured CO_2 and transporting it via pipeline to sites where it can be injected into Underground Injection Control ("UIC") wells for secure geologic sequestration. Additionally, we have engaged Project Canary to analyze and report the CO_2e injection volumes and environmental attributes of our sequestration projects, and we are working with the American Carbon Registry to certify and register the environmental attributes associated with our CCUS projects as tradeable carbon credits. In the future, we may sell carbon credits associated with our CCUS projects to unrelated third parties outside of our value chain, which may negatively impact our net zero strategy, including by delaying or preventing our achievement of net zero.

Although we formally launched our CCUS business in March 2022 with the establishment of BKV dCarbon Ventures, we have been evaluating project opportunities and developing our CCUS business since early 2021. The development of our CCUS business has progressed rapidly, supported by internal geology, engineering, operations, business development, land, regulatory and other professionals, along with academics and CCUS-focused partnerships. We believe that with a continued and timely execution of our business plans, the Barnett Zero Project could begin generating positive net income via tax credits in 2024. We expect to fund up to 50% of our CCUS business from a variety of external sources, which may include joint ventures, project-based equity partnerships and federal grants, with the remaining capital needs being funded with cash flows from operations. The projected timeline for commercial operations and the generation of positive CCUS business revenue and positive earnings depends, in part, on our ability to fund the anticipated capital requirements for the potential projects that we have identified and described below through external funding and revenues from our upstream business, as well as on our ability to receive our portion of the anticipated Section 45Q tax credits associated with these projects. We may not receive 100% of the Section 45Q tax credits associated with projects funded by third parties and, in such cases, will receive only a corresponding percentage of the anticipated Section 45Q tax credits associated with such projects.

We seek to execute CCUS projects with attractive standalone economics and the ability to sequester emissions from both our own operations and from third-party operations. For example, we plan to target CCUS projects with high concentration CO_2 streams where revenue, taking into account tax incentives, less cash operating expense would generally be expected to be between $40 and $70 per metric ton of sequestered CO_2e for the first six years of commercial operations for projects owned by BKV. We may also provide development and support services for third-party owned CCUS projects on a fee-for-service model, although such projects will not be included in our path to net zero. We are also evaluating potential third party investments in our CCUS business, which may accelerate the development of our CCUS projects; however, depending on the terms of such investment, this may impact the ultimate number of carbon credits we may receive from such projects.

As part of our "closed-loop" approach to our net zero emissions goal, we expect to apply a portion of the CO_2 emissions that are sequestered through our CCUS business to offset GHG emissions from our owned and operated upstream and natural gas midstream businesses. We may not receive 100% of the environmental attributes associated with CCUS projects funded in whole or in part by third parties, and, in such cases, we expect to have the right to purchase such environmental attributes BKV would not otherwise receive. Ultimately, we will be able to apply only such portion of the sequestered emissions to offset our own GHG emissions that corresponds to the percentage of environmental attributes BKV receives or purchases. We expect our CCUS business to contribute in significant part to our goals to fully offset our Scope 1 and 2 emissions from our owned and operated upstream and natural gas midstream businesses by the early 2030s, and our Scope 1, 2 and 3 emissions from our owned and operated upstream and natural gas midstream businesses by the late 2030s. See "— *Path to Net Zero Emissions*" below for a description of how we estimate our Scope 1, 2 and 3 annual emissions and how we expect our CCUS business to contribute to the offset of those emissions.

CCUS Projects

Currently, we have one operational CCUS project and are pursuing sixteen additional potential CCUS projects that we believe are commercially viable based on economics supported by enhanced Section 45Q tax credits and that we believe can be completed by the late 2030s. We have entered into various letters of intent and definitive contracts that we expect to grant us carbon storage and sequestration rights on over 44,000 acres of leased pore space across seven distinct projects located in three states, with total reservoir storage capacity of over 1 billion metric tons of CO_2e. We have filed applications to seek Class VI permits for two of these pore space locations, one of which is in the State of Louisiana. The EPA recognized our permit applications as being administratively complete in January 2024 and February 2024, respectively, and then transferred our permit application applicable to the Louisiana pore space location to the State of Louisiana, which assumed primacy for Class VI well permitting. The Louisiana Department of Energy and Natural Resources declared our permit application administratively complete in July 2024. The EPA expects to complete its technical review of our other permit application by September 2025. Our projected timeline for commercial operations of these sixteen projects depends in part on our ability to fund the capital requirements for these potential projects through external funding and revenues from our upstream business. Our timeline also depends on a regulatory environment that is favorable to our projects and their development. Our potential projects can be placed into six categories: (i) operational projects, (ii) projects that have reached FID, but are not yet operational, (iii) identified NGP projects under evaluation, (iv) identified industrial projects under evaluation, (v) identified ethanol projects under evaluation, and (vi) other potential projects that have been identified but not yet sufficiently evaluated. We have achieved notable milestones with respect to several of the seventeen projects within the first five categories, as more fully described below.

Project	Status[(1)]	Actual or Forecasted Initiation of Sequestration Operations[(2)]	Forecasted Annual Sequestration Volumes (Mtpy CO_2e)[(3)]
Barnett Zero	Operating	November 2023	0.18
Cotton Cove	FID	1H 2026	0.04
8 NGP Projects	Pre-FID	2025 – 2029	2.68
3 Industrial Projects	Pre-FID	2026 – 2027	11.15
4 Ethanol Projects	Pre-FID	2027 – 2029	2.56

(1) We have not secured external financing, reached FID or entered into the definitive agreements necessary to execute any of the pre-FID projects identified above.

(2) Our projected timeline for commencement of sequestration operations at the Cotton Cove Project and all of the pre-FID projects identified above depends in part on our ability to fund the capital requirements for these potential projects through external funding and revenues from our upstream business, as well as a regulatory environment that is favorable to our projects and their development. See "*Risk Factors — Risks Related to Our CCUS Business.*"

(3) We may not receive 100% of the environmental attributes associated with CCUS projects funded in whole or in part by third parties, and, in such cases, we expect to have the right to purchase such environmental attributes BKV would not otherwise receive. Ultimately, we will be able to apply only such portion of the sequestered emissions to offset our own GHG emissions that corresponds to the percentage of environmental attributes BKV receives or purchases.

Operational Projects

Barnett Zero Project. In November 2023, our first CCUS project, which we refer to as the Barnett Zero Project, commenced commercial sequestration of CO_2 waste generated by EnLink's Bridgeport natural gas processing plant and neighboring operations. In the Barnett Zero Project, EnLink transports our natural gas produced in the Barnett to its natural gas processing plant in Bridgeport, Texas, where the CO_2 waste stream is captured, compressed and then disposed of and sequestered via our nearby injection well. The Barnett Zero Project is an NGP project that separates CO_2 from substantially all of our EnLink-gathered natural gas production. We initially reached FID and entered into a definitive agreement with EnLink for the Barnett Zero Project in June 2022, subsequently drilled a Class II well that complies with standards applicable to Class VI wells, obtained EPA-approval of our Monitoring, Reporting and Verification Plan, as required by the EPA's Greenhouse Gas Reporting Program, and commenced operations with first injection in November 2023. We expect the Barnett Zero Project to achieve an average sequestration rate of approximately 183,000 metric tons of CO_2e per year and to require a total investment by us of approximately $36.0 million, of which $34.0 million has been invested as of December 31, 2023.

We intend to use the Barnett Zero Project as a prototype for modular NGP projects that can be repeated and quickly scaled. We are currently progressing eight NGP projects based on this model and anticipate that these projects will reach FID at various points in 2025 through 2029.

FID Projects

Cotton Cove Project. On October 18, 2022, BKV dCarbon Ventures reached internal FID to develop our second CCUS project in the Barnett. This CCUS project, which we refer to as the Cotton Cove Project, will separate, dispose of and geologically sequester CO_2 generated as a byproduct of our natural gas production in the Barnett and will utilize our midstream assets to do so. We have multiple pore space opportunities for CO_2 injection, and we estimate the Cotton Cove Project will geologically sequester up to approximately 40,000 metric tons of CO_2 per year, and we expect to be entitled to use 100% of the environmental attributes associated with such volumes towards our net zero goals. The Cotton Cove Project is held through BKV-BPP Cotton Cove LLC (“BKV-BPP Cotton Cove” or the “BKV-BPP Cotton Cove Joint Venture”), a joint venture owned 51% by BKV dCarbon Ventures and 49% by BPPUS. We currently estimate the total investment required for the Cotton Cove Project to be approximately $17.6 million, of which we will be required to contribute approximately $9.0 million and under the terms of an agreement with BPPUS, we expect to be entitled to use 100% of the environmental attributes associated with such volumes towards our net zero goals. We are targeting commencement of CO_2 sequestration activities in the first half of 2026, subject to our ability to secure all required permits, at which point we expect this project will be the second of our current modular line of identified potential NGP projects, in addition to the Barnett Zero Project. Additionally, BKV dCarbon Ventures will manage the BKV-BPP Cotton Cove Joint Venture and leverage our existing organization to provide marketing, engineering, finance, operations, project management, accounting and other administrative services to the BKV-BPP Cotton Cove Joint Venture, in each case for an annual fee plus expenses. For additional information about the BKV-BPP Cotton Cove Joint Venture, see “*Certain Relationships and Related Party Transactions — BKV-BPP Cotton Cove Joint Venture — BKV-BPP Cotton Cove Limited Liability Company Agreement.”*

We are also evaluating expansion of the Barnett Zero and Cotton Cove Projects to pilot, and then scale, post-combustion carbon capture technology that would allow us to sequester up to an additional approximately 250,000 metric tons per year of captured CO_2e from low concentration emissions from within our natural gas midstream and/or other nearby processing operations. As part of this process, we intend to capture CO_2e from sources such as compressor exhaust flues and utilize compressor waste heat to reduce energy requirements and cost.

NGP Projects

We have identified eight potential NGP projects that we anticipate will achieve FID and commence initial sequestration operations at various points in 2025 through 2029. If approved and implemented, we anticipate that these eight projects would sequester third-party emissions, require a total capital investment by us of approximately $440.0 million by December 31, 2029 and thereafter provide a combined forecasted annual sequestration volume of approximately 2.68 million metric tons per year of captured CO_2e.

A significant portion of the carbon capture infrastructure necessary to execute these eight potential NGP projects already exists. For example, we entered into definitive agreements for pore space leasehold that would provide approximately 45 million metric tons of CO_2e sequestration capacity for one project, and, in connection with our development of another project, entered into a definitive agreement with a local emitter for the transfer and purchase of the CO2 waste stream from its natural gas processing plant. Therefore, if approved at FID, and assuming we are able to execute definitive agreements on the terms and timeline we believe are obtainable and secure sufficient external funding, we expect these projects to start sequestration operations before December 31, 2029.

Industrial Projects

We are currently evaluating three potential medium to higher concentration industrial projects to sequester third-party emissions, which we anticipate will achieve FID and commence initial sequestration operations at various points in 2026 through 2027. If approved and implemented, these three projects would provide a combined forecasted annual sequestration volume of approximately 11.15 million metric tons per year of captured CO_2e.

Pore space leaseholds have been secured for all three of these projects, including one covering approximately 21,000 acres of state-owned land in Louisiana, which project we refer to as the High West Project.

In August 2023, High West Sequestration, LLC ("High West"), a wholly owned subsidiary of BKV dCarbon Ventures, entered into a carbon sequestration agreement with the State of Louisiana to develop facilities and permanently sequester CO_2 from local third-party emissions sources. The State of Louisiana granted High West the carbon storage and sequestration rights on approximately 21,000 acres of land in St. Charles and Jefferson Parishes. The acreage is in an ideal location for targeted carbon capture and sequestration efforts, with an estimated 22 Mtpy CO_2e of potential capture and sequestration located within a 20 mile radius from various emissions points. In addition, the storage site has a large CO_2 storage potential, estimated to be between 140 to 1,000 Mtpy CO_2, subject to further evaluation, planning and development design decisions. Under the agreement, High West will dispose of CO_2e waste from local third-party emissions sources through permanent sequestration via injection wells on the designated acreage. This project, which we refer to as the High West Project, is expected to reach FID by the end of 2024. BKV dCarbon Ventures engaged NuQuest Energy, LLC to provide CCUS marketing and development services for the High West Project.

We have filed applications to seek Class VI permits for two of these industrial projects, one of which is in the State of Louisiana. The EPA recognized our permit applications as being administratively complete in January 2024 and February 2024, respectively, and then transferred our permit application applicable to the Louisiana pore space location to the State of Louisiana, which assumed primacy for Class VI well permitting. The Louisiana Department of Energy and Natural Resources declared our permit application administratively complete in July 2024. The EPA expects to complete its technical review of our other permit application by September 2025. We also anticipate that a Class VI permit application for the third project will be submitted by August 2024. If each of these projects is approved at FID, and we are able to secure sufficient external financing and assuming definitive agreements are timely executed containing terms we believe are obtainable, we expect to initiate sequestration operations between 2026 and 2027. Verde CO_2 has the option to purchase up to a 5% minority economic interest in two of these potential industrial projects and, to the extent it exercises such option, would be entitled to a pro rata share of the Section 45Q tax credits associated with the CCUS projects in which it invests.

Ethanol Projects

We have identified four potential ethanol projects that we anticipate will achieve FID and commence initial sequestration operations at various points during 2027 through 2029. If approved and implemented, we anticipate that these four projects would sequester third-party emissions, require a total capital investment by us of approximately $680 million by December 31, 2029, and thereafter provide a combined forecasted annual sequestration volume of approximately 2.56 million metric tons per year of captured CO_2e.

If each of these projects is approved at FID and assuming we are able to execute definitive agreements on the terms and timeline we believe are obtainable and secure sufficient external funding, we expect to begin sequestration operations between 2027 and 2029.

In addition to these sixteen identified potential projects, we are currently evaluating more than ten early-stage project opportunities that are aligned with our high concentration strategy but are not yet sufficiently evaluated to determine potential sequestration volumes, geologic feasibility or timeline of completion. We also evaluate later-stage opportunistic CCUS project acquisition opportunities. In the event a potential project listed above is not progressed for any reason, including failure to FID, or additional funding provides for greater capacity to complete projects, we may further evaluate and develop one or more of these early-stage project opportunities.

Our CCUS business of capturing and sequestering emissions from our operations and from operations of third parties is a critical component of our “closed-loop” approach to achieving our goal of net zero Scope 1 and 2 emissions from our owned and operated upstream and natural gas midstream businesses by the early 2030s and Scope 1, 2 and 3 emissions from our owned and operated upstream and natural gas midstream businesses by the late 2030s. We expect to continue to identify and evaluate additional CCUS projects and we believe that we will be able to complete a sufficient number of the above-described or other CCUS projects in order to meet our Scope 1, 2 and 3 emissions goals. See “— *Path to Net Zero Emissions*” for a more detailed description of how we anticipate reaching our Scope 1, 2 and 3 emissions goals.

However, we have not secured external financing, reached FID or entered into the definitive agreements necessary to execute any of the pre-FID projects identified above, and there can be no guarantee that we will be able to execute and operate any of the sixteen identified potential CCUS projects (or any other CCUS projects) with sufficient volumes of CO_2e sequestration to achieve our Scope 1, 2 and 3 emissions goals on the timelines we anticipate. There can be no assurance that any of the sixteen identified CCUS projects discussed above, the Barnett Zero Project or any other CCUS project will achieve the forecasted sequestration volumes, and we may not commence sequestration operations for any of the projects identified above by the anticipated timeframe, or at all. Furthermore, we may not receive 100% of the environmental attributes associated with CCUS projects funded in whole or in part by third parties, and, in such cases, we expect to have the right to purchase such environmental attributes BKV would not otherwise receive. Ultimately, we will be able to apply only such portion of the sequestered emissions to offset our own GHG emissions that corresponds to the percentage of environmental attributes BKV receives or purchases. While we may consider alternatives to offset our owned and operated upstream and natural gas midstream emissions (including the purchase of verified offset credits) in order to meet our Scope 1, 2 and 3 emissions goals, ultimately, we may not be able to achieve our goals of net zero Scope 1 and 2 emissions from our owned and operated upstream businesses and natural gas midstream by the early 2030s or net zero Scope 1, 2 and 3 emissions from our owned and operated upstream businesses and midstream businesses by the late 2030s.

We estimate the aggregate investment required to develop the seventeen identified actual and potential CCUS projects to be between approximately $1.3 – 1.8 billion between now and the end of 2030. We anticipate that some of these project costs will be borne by third-party investors in these projects, including owners of sources of CO_2e, landowners and other stakeholders. In order to achieve the projected timeline for commercial operations of such projects, we expect to fund the anticipated cost of these CCUS projects with a combination of up to 50% from third party sources, which may include joint ventures, project-based equity partnerships and federal grants, with the remaining capital needs being funded with cash flows from operations. We are able to moderate the capital required to fund our CCUS business, as our CCUS business model provides flexibility for us to selectively invest in only the sequestration component of a project or in the capture, transportation and sequestration components, depending on the scope of the project. Therefore, if sufficient external funding is not available, then we would expect to continue to develop our CCUS business from cash flows from operations on a less accelerated timeline, which may result in an inability to achieve our Scope 1, 2 and 3 emissions goals on the timeline we anticipate.

Our CCUS business and all of our CCUS projects are in the early stages of development. Although we commenced commercial operations with the initial injection of CO_2 waste at the Barnett Zero Project on November 13, 2023, and have reached FID and entered into definitive agreements with respect to the Cotton Cove Project, we have not reached FID with respect to or entered into the definitive agreements necessary to execute any of the other fifteen potential projects identified above. We may not be able to reach agreements on terms acceptable to us or achieve our projected timeline for commercial operations for these projects. In addition, the development of our CCUS business is expected to require material capital investments, and the projected timeline for commercial operations depends on our ability to fund the anticipated capital requirements for the potential projects that we have identified through external funding and revenues from our upstream business. Furthermore, the commercial viability of our CCUS projects depends, in part, on obtaining necessary permits and other regulatory approvals and on our ability to receive our portion of the anticipated Section 45Q tax credits associated with these projects. In particular, we must meet certain wage and apprenticeship requirements in order to qualify for enhanced Section 45Q tax credits. For more information about the risks involved in our CCUS business, see "*Risk Factors — Risks Related to Our CCUS Business.*"

To help us achieve our goal of becoming a leader in CCUS, we established a steering committee that includes two engineers renowned for their work in the development of CCUS projects: Dr. Paitoon (P.T.) Tontiwachwuthikul (Professor of Industrial & Process Systems Engineering & Fellow, Canadian Academy of Engineering) and Dr. Malcolm A. Wilson (Program Director, CO_2 Management, Office of Energy & Environment (OEE), Adjunct Professor of Engineering and Graduate Studies). These individuals are professors at the University of Regina, a leading carbon capture research institution, and each has been engaged in CCUS for over 30 years.

Path to Net Zero Emissions

We conducted an initial assessment of our annual Scope 1 and 2 emissions from our owned and upstream businesses as of December 31, 2021, and subsequently updated that assessment for the upstream and natural gas midstream businesses acquired through the Exxon Barnett Acquisition in 2022 to establish an emissions baseline of 2.49 Mtpy CO_2e annual Scope 1 and 2 emissions from our owned and operated upstream and natural gas midstream businesses as of December 31, 2021. Our assessments did not address our GHG emissions from our other business operations.

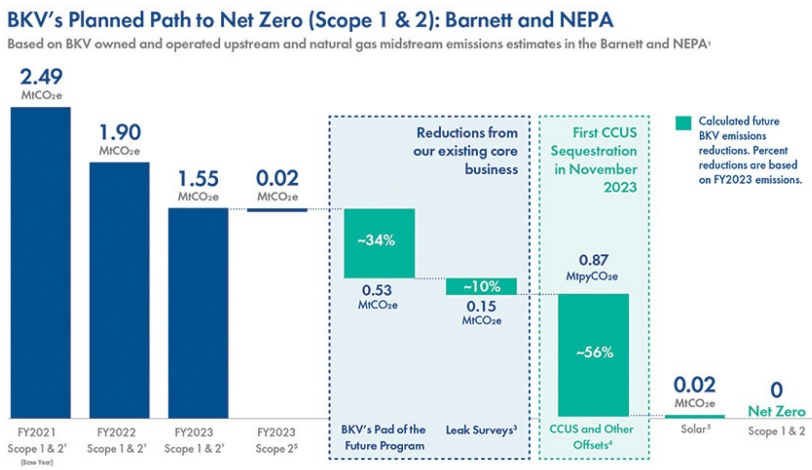
We have made progress in the reduction of our annual Scope 1 and 2 emissions from our owned and operated upstream and natural gas midstream businesses since December 31, 2021. We estimate that our Scope 1 and 2 annual emissions from our owned and operated upstream and natural gas midstream businesses were approximately 1.9 Mtpy CO_2e as of December 31, 2022 and 1.55 Mtpy CO_2e as of December 31, 2023, reflecting a reduction of approximately 0.9 Mtpy CO_2e from our baseline emissions assessment established as of December 31, 2021. This reduction is due primarily to the implementation of our "Pad of the Future" and leak detection and repair programs, which began in the fourth quarter of 2021 and occurred throughout 2022 and 2023. During this time frame, our "Pad of the Future" program has eliminated 0.52 Mtpy CO_2e, or 21%, of our annual Scope 1 and 2 emissions from our owned and operated upstream and natural gas midstream businesses, and improvements in our emission quantification methods and the implementation of site-level leak detection and repair programs have resulted in the elimination of an additional 0.42 Mtpy CO_2e, or 17%, of our annual Scope 1 and 2 emissions from our owned and operated upstream and natural gas midstream businesses. In total, this represents a 0.94 Mtpy CO_2e or 38% reduction of our annual GHG emissions from our baseline emissions assessment established as of December 31, 2021.

Our emissions estimates presented in this prospectus are based on information with respect to our owned and operated upstream and natural gas midstream businesses in the Barnett and NEPA through fiscal year 2023 and reported by BKV pursuant to the Subpart C and Subpart W, as applicable, requirements of the federal Clean Air Act GHG reporting program regulations of the EPA. These estimates will be updated annually to reflect any changes in activity, inventory, production throughput and emissions reduction retrofits or equipment modifications.

We estimate that our annual Scope 3 emissions from our owned and operated upstream and natural gas midstream businesses were approximately 18.7 Mtpy CO_2e as of December 31, 2023. These Scope 3 emissions are currently estimated in accordance with IPIECA's "Sustainability reporting guidance for oil and gas industry," dated March 2020. Specifically, Scope 3 emissions are estimated per the Greenhouse Gas Protocol's "Corporate Value Chain (Scope 3) Accounting and Reporting Standard," released in 2011, under Category 11 (Use of Sold Product). Scope 3 emissions estimated using source Category 11 represent the majority of Scope 3 emissions from our owned and operated upstream and natural gas midstream operations, with minor contributions from other source categories. Additionally, our estimated Scope 3 emissions calculations assume that all natural gas produced is combusted and does not account for other potential end uses of natural gas. Scope 3 mass emissions are calculated using the EPA's prescribed emissions factors for the speciated natural gas (methane and ethane) as well as NGLs assuming Y-grade NGLs. CO_2e emissions are estimated using AR4 Global Warming Potentials, similar to those used by the EPA. Our projected annual Scope 3 CO_2e emissions are estimated at an approximated year-end net production volume of 942 MMcfe/d of natural gas (approximately 85% methane, 5% ethane and 10% other) and approximately 139.4 MBbls of

NGLs (or approximately 2 MMcfe/d), as reported to the EPA for Subpart W. Our NGL constituents are estimated based on average constituent NGL barrel. Allocating the entire 944 MMcfe/d towards combustion as the end use, applying suitable combustion emission factors from the EPA, and using AR4 GWPs, Scope 3 annual emissions from our owned and operated upstream operations are estimated to be approximately 18.7 Mtpy CO_2e. We currently engage third party consultants to develop and review our Scope 3 emissions estimates.

The charts below reflect (i) our estimated annual Scope 1 and 2 emissions from our owned and operated upstream and natural gas midstream businesses as of December 31, 2023, and (ii) our estimated annual Scope 3 emissions from our owned and operated upstream and natural gas midstream businesses as of December 31, 2023. These two charts also reflect our intended path to net zero Scope 1 and 2 emissions by the early 2030s and net zero Scope 1, 2 and 3 emissions by the late 2030s, in each case, for our owned and operated upstream and natural gas midstream businesses. These charts do not address our GHG emissions from our other business operations. As part of our "closed-loop" approach to our emissions goals, we intend to achieve these goals through our "Pad of the Future" emissions reductions, reductions attributable to emissions monitoring and leak surveys, emissions offsets from the retirement of SRECs generated by the BKV-BPP Power Joint Venture's planned solar facility and executing CCUS projects to sequester our and third-party emissions.



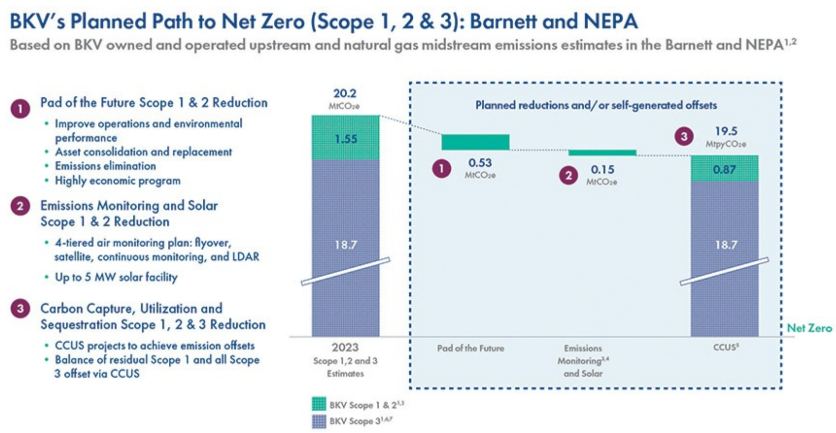
(1) These emissions estimates are based solely on our owned and operated upstream and natural gas midstream businesses. These emissions estimates do not reflect our GHG emissions from our other business operations, namely our CCUS operations and our power generation business through the BKV-BPP Power Joint Venture.

(2) Scope 1 calculated emissions are based on those reported to US EPA per Subpart W.

(3) Emissions surveys accomplished per US EPA Subpart W to reduce emissions.

(4) We achieved first injection of CO_2 waste at the Barnett Zero Project in November 2023.

(5) Retirement of the SRECs generated by the BKV-BPP Power Joint Venture's planned 2.5 MW to 5 MW solar facility is expected to offset up to 32% of current scope 2 emissions. The BKV-BPP Power Joint Venture has constructed a 2.5 MW solar facility, which will soon be operational and is in the process of obtaining permits for the remaining 2.5 MW. BKV expects to purchase the SRECs generated by the solar facility or will purchase off of the market to offset Scope 2 emissions.



(1) These emissions estimates are based solely on our owned and operated upstream and natural gas midstream businesses. These emissions estimates do not reflect our GHG emissions from our other business operations, namely our CCUS operations and our power generation business through the BKV-BPP Power Joint Venture.

(2) Scope 1 and 2 calculated emissions are based on 791 MMscf/d production volume for 2023 Subpart W in the Barnett and 151 MMscf/d production volume for 2023 Subpart W in NEPA.

(3) Emissions surveys accomplished per US EPA Subpart W to reduce emissions.

(4) We achieved first injection of CO_2 waste at the Barnett Zero Project in November 2023.

(5) Retirement of the SRECs generated by the BKV-BPP Power Joint Venture's planned 2.5 MW to 5 MW solar facility is expected to offset up to 32% of current scope 2 emissions. The BKV-BPP Power Joint Venture has constructed a 2.5 MW solar facility, which will soon be operational and is in the process of obtaining permits for the remaining 2.5 MW. BKV expects to purchase the SRECs generated by the solar facility or will purchase off of the market to offset Scope 2 emissions.

(6) Scope 3 calculated emissions are based on an estimated net production rate of approximately 944 MMcfe/d (approximately 944 MMscf/d of natural gas and 2 MMscfe/day of NGLs) as reported to US EPA for CY 2023 Subpart W.

(7) Scope 3 calculated emissions are estimated assuming combustion-based usage of all produced natural gas and NGLs. Approximately 58% of NGLs are assumed to be combusted for fuel while 100% of all natural gas sold is assumed to be combusted for fuel. Scope 3 emissions estimation methodology is therefore considered to be conservative.

Planned Path to Net Zero (Scope 1 and 2)

Pad of the Future. Our "Pad of the Future" program implements pad level design improvements to reduce pad level usage of natural gas, reduce GHG emissions and maintain operational continuity. As of December 31, 2023, we had implemented elements of our "Pad of the Future" program on approximately 3,200 of our existing wells and we have successfully completed the implementation of the "Pad of the Future" program for our upstream owned and operated assets in NEPA. As a result, as compared to our 2021 baseline assessment, we have achieved a reduction in our estimated annual GHG emissions of approximately 0.53 Mtpy CO_2e. These reductions are calculated by using our pneumatic and other pad inventories, and such emissions are factored to be eliminated once the system has been converted from natural gas supplied to compressed air or electric.

We plan to implement elements of our "Pad of the Future" program on more than 6,000 of our existing wells (more than 16,500 pneumatic devices and 3,000 pneumatic pumps) by the end of 2027 for an aggregate estimated cost of approximately $35 to $40 million. Once this expansion is completed, we expect to eliminate approximately 1.0 Mtpy CO_2e of the currently estimated Scope 1 annual emissions from our owned and operated upstream and natural gas midstream businesses.

Emissions Monitoring and Solar. Our leak detection and repair emissions monitoring program involves continuous ground-based instrument monitoring, satellite-based monitoring, aerial flyovers and on the ground leak detection and repair inspections. In addition, we expect to purchase the SRECs generated by the BKV-BPP Power Joint Venture's planned 2.5 MW to 5 MW solar facility, which is scheduled to begin construction and generating power in 2024. The BKV-BPP Power Joint Venture has obtained permits for and is constructing 2.5 MW and is in the process of obtaining permits for the remaining 2.5 MW. Solar facilities may be subject to increasingly arduous regulatory requirements, including additional permitting requirements. For every 1,000 kilowatt-hours of electricity produced by an eligible solar facility, one SREC is awarded. For a solar facility to be credited with that SREC, the system must be certified and registered by state agencies. The BKV-BPP Power Joint Venture's planned solar facility is expected to generate SRECs to offset up to 32% of current GHG emissions. The SRECs BKV expects to purchase and retire are reflected in the charts above as neutralizing a portion of our annual Scope 2 emissions from purchased energy for our owned and operated upstream and natural gas midstream business.

CCUS. Further, as discussed under "— *Carbon Capture, Utilization and Sequestration*" above, we believe that the Barnett Zero Project, together with the Cotton Cove Project and the eight NGP projects, three industrial projects and four ethanol projects for the capture and sequestration of third-party emissions that we have identified, have a combined annual forecasted sequestration volume of approximately 16.61 Mtpy CO_2e by the end of 2029, which is greater than the approximately 0.87 Mtpy CO_2e annual Scope 1 and 2 emissions from our owned and operated upstream and natural gas midstream businesses that we currently estimate will remain after taking into account the expected emissions reductions and offsets from our "Pad of the Future" program, emissions monitoring and leak surveys and the retirement of SRECs generated by the BKV-BPP Power Joint Venture's planned solar facility that we expect to purchase. Although we have not secured external financing, reached FID or entered into the definitive agreements necessary to execute any of the eight NGP projects, three industrial projects or four ethanol projects we have identified, we expect these projects to reach FID and commence sequestration operations by the end of 2029. A significant portion of the carbon capture infrastructure necessary to execute the NGP projects already exists and, as discussed above, we continue to accomplish important milestones consistent with our projected timeline. If approved at FID, and assuming we are able to execute definitive agreements on the terms and timeline we believe are obtainable and secure sufficient external funding, we expect these projects to start sequestration operations before December 31, 2029.

If we are unable to complete these fifteen projects and the Cotton Cove Project before December 31, 2029, or enter into commercial agreements in connection with these projects that result in BKV receiving less than 100% of the associated emissions offsets, carbon credits or other environmental attributes, we may still reach our Scope 1 and 2 emissions goals with less than all of these projects completed, as the annual forecasted sequestration volume of (i) the Barnett Zero Project is 183,000 metric tons of captured CO_2e per year, (ii) the Cotton Cove Project is 40,000 metric tons of captured CO_2e per year, (iii) the eight potential NGP projects is an aggregate 2.68 million metric tons of captured CO_2e per year, (iv) the three potential industrial projects is an aggregate 11.15 million metric tons of captured CO_2e per year and (v) the four potential ethanol projects is an aggregate 2.56 million metric tons of captured CO_2e per year.

However, we have not secured external financing, reached FID or entered into the definitive agreements necessary to execute any of the pre-FID projects identified above, and there can be no guarantee that we will be able to execute and operate any of the sixteen identified potential CCUS projects (or any other CCUS projects) with sufficient volumes of CO_2e sequestration to achieve our Scope 1, 2 and 3 emissions goals on the timelines we anticipate. There can be no assurance that any of the potential projects we have identified or the Barnett Zero Project will achieve forecasted sequestration volumes, and we may not commence sequestration operations for any of the potential projects identified above by the anticipated timeframe, or at all. Furthermore, we may not receive 100% of the environmental attributes associated with CCUS projects funded in whole or in part by third parties, and, in such cases, we expect to have the right to purchase such environmental attributes BKV would not otherwise receive. Ultimately, we will be able to apply only such portion of the sequestered emissions to offset our own GHG emissions that corresponds to the percentage of environmental attributes BKV receives or purchases. While we may consider alternatives to offset our owned and operated upstream and natural gas midstream emissions (including the purchase of verified offset credits) in order to meet our Scope 1 and 2 emissions goals, ultimately, we may not be able to achieve our goals of net zero Scope 1 and 2 emissions from our owned and operated upstream businesses and natural gas midstream by the early 2030s.

Planned Path to Net Zero (Scope 1, 2 and 3)

We also aspire to offset the annual Scope 3 emissions impact of our owned and operated upstream and natural gas midstream businesses by the late 2030s, which we estimate to be approximately 18.7 Mtpy CO_2e annually as of December 31, 2023. Our CCUS business of capturing and sequestering our and third-party emissions is a critical component to achieving this net zero goal. This aspiration to offset the Scope 3 emissions of our owned and operated upstream and natural gas midstream businesses by the late 2030s is limited to our Category 11 (Use of Sold Product) emissions, which we believe represents a significant portion of the overall Scope 3 emissions from our owned and operated upstream and natural gas midstream businesses. However, our Scope 3 emissions estimate does not include our GHG emissions from our other business operations, namely our CCUS and power generation businesses.

As discussed in "— *Carbon Capture, Utilization and Sequestration*," above, we are currently operating the Barnett Zero Project and have identified sixteen potential CCUS projects that we believe are commercially viable and estimate would have a combined forecasted annual volume of carbon capture and sequestration of approximately 16 Mtpy CO_2e, which represents approximately 79% of our current Scope 1, 2 and 3 annual emissions from our owned and operated upstream and natural gas midstream businesses, and represents approximately 82% of our current Scope 1, 2 and 3 annual emissions from our owned and operated upstream and natural gas midstream businesses after taking into account the expected emissions reductions and offsets from our "Pad of the Future" program, emissions monitoring and leak surveys and the retirement of SRECs generated by the BKV-BPP Power Joint Venture's planned solar facility that we expect to purchase. In addition, we are currently evaluating more than ten early-stage project opportunities that are aligned with our high concentration strategy and have been identified, but are not yet sufficiently evaluated to determine potential sequestration volumes, geologic feasibility or timeline of completion. We also evaluate later-stage opportunistic CCUS project acquisition opportunities. In the event a potential project is not progressed for any reason, including failure to FID, or additional funding provides for greater capacity to complete projects, we may further evaluate and develop one or more of these early-stage project opportunities. We will continue to evaluate and identify potential CCUS project opportunities consistent with our goal of offsetting our annual Scope 1, 2 and 3 emissions from our owned and operated upstream and natural gas midstream businesses by the late 2030s. However, we may not receive 100% of the environmental attributes associated with CCUS projects funded in whole or in part by third parties, and, in such cases, we expect to have the right to purchase such environmental attributes BKV would not otherwise receive. Ultimately, we will be able to apply only such portion of the sequestered emissions to offset our own GHG emissions that corresponds to the percentage of environmental attributes BKV receives or purchases.

Large scale CCUS projects are subject to numerous risks and uncertainties, including securing third-party financing, reaching definitive agreements with third parties and obtaining necessary permits and other regulatory approvals, and we may be unable to execute on some or all of these projects, including the projects for which we have reached FID, on the timeline we anticipate, on terms acceptable to us or at all. There can be no guarantee that we will be able to execute and complete any of these identified CCUS projects and there can be no guarantee that we will be able to achieve our net zero Scope 1, 2 and 3 emissions goals. The projected timeline for commercial operations of our CCUS projects depends in part on our ability to fund the anticipated capital requirements for the potential projects that we have identified through up to 50% third party equity or debt funding together with revenues from our upstream business. If sufficient external funding is not available, then we would expect to continue to develop our CCUS business from cash flows from operations on a less accelerated timeline. If we are not able to complete CCUS projects having a sufficient forecasted volume of carbon capture to offset our Scope 1, 2 and 3 annual emissions on the timeline and upon terms that we believe are obtainable, we may not be able to achieve our goal of net zero Scope 1, 2 and 3 emissions from our owned and operated upstream and natural gas midstream businesses by the late 2030s.

In addition, our path to net zero solely addresses GHG emissions relating to our owned and operated upstream and natural gas midstream businesses and does not address GHG emissions from our other business operations, namely our CCUS and power generation businesses. Our power generation business is operated through the BKV-BPP Power Joint Venture, which owns the Temple Plants. Although we believe our current path to net zero will be sufficient to reduce emissions related to our existing owned and operated upstream and natural gas midstream businesses, the future growth or expansion of such businesses will result in additional GHG emissions. We believe our approach to reducing the emissions from our owned and operated upstream and natural gas midstream operations is repeatable and scalable. Through continued investment and expansion of our "Pad of the Future" program and our emissions and leak surveys, as well as additional CCUS and solar projects, we believe we will be able to offset any such additional emissions from our owned and operated upstream and natural gas midstream businesses resulting from our continued growth.

Business Strategy

Our strategy is to create value for our stockholders by managing and growing our integrated asset base and focusing on our net zero objectives. Our strategy has the following principal elements:

- **Optimize the value of our core businesses.** We utilize technology and data analysis to enhance our assets and operations, which we believe improves operational efficiencies, reduces our emissions and helps us realize our operational and financial goals as we continue to scale our business. For example, our "Pad of the Future" program, which includes conversion of natural gas-powered instrument pneumatics to compressed air or electric power instruments on existing pads, combined with emission and leak surveys, is expected to eliminate or reduce approximately 1.05 Mtpy CO_2e of our annual GHG emissions by the end of 2027. Our "Pad of the Future" application also improves pad efficiencies and operating revenue. We have also improved pad efficiencies and reduced lease operating costs through improvements including leveraging of data analytics to coordinate the workforce, prioritize high-value activity, and assess individual well profitability; automating critical plunger set points; in-sourcing key services such as slick-line, value re-builds, compression overhaul, and location repair and maintenance; as well as entering water share arrangements to reduce disposal and trucking cost. Through these process improvements, we reduced our operating costs for our operated NEPA assets by 33.0% for the trailing twelve months ended June 30, 2024, as compared to the trailing twelve months ended March 31, 2019, which period represented the first year of our operatorship of the NEPA assets. Similarly, we reduced our operating costs for our Barnett assets by 12.8% for the trailing twelve months ended June 30, 2024, as compared to the trailing twelve months ended June 30, 2023, which period represented the first year of our operatorship of the Barnett assets acquired from the Exxon Barnett Acquisition and the Devon Barnett Acquisition combined. Additionally, our refrac and long lateral drill programs have allowed us to organically grow our reserves base. As of December 31, 2023, our Barnett refrac program has added 317 Bcfe of proved reserves since its inception in early 2021. As of December 31, 2023, our Barnett refrac program has an average of $0.57/Mcfe in finding and development costs with respect to proved reserves. This refrac program employs specifically designed perforating technology and a suite of innovative refrac techniques, as well as advanced refrac designs and diversion methods to maximize reserves recovery and economics from legacy Barnett wells. Our Barnett new well drilling program has added 645 Bcfe of proved reserves since our entry into the Barnett. By combining our reserves into a growing asset base with vertically integrated components, we believe we can enhance margins and create a "closed loop" emissions reduction strategy that reduces Scope 1 and 2 emissions from our owned and operated upstream and natural gas midstream businesses and captures margin across the value chain.
- **Grow through opportunistic, synergistic acquisitions.** A significant element of our business strategy is gaining scale through accretive acquisitions. We have a track record of growth through acquisitions, which we believe have been at attractive valuations. Since 2016, we have completed 19 acquisitions resulting in approximately 69% compound annual growth rate of Adjusted EBITDAX as of June 30, 2024. We believe our business model, management team experience and application of technology enable us to quickly and efficiently integrate additional upstream, midstream, power and CCUS assets into our business.
- **Maintain a disciplined financial strategy.** We believe we can execute on our business plan and grow our business while continuing to generate substantial Adjusted Free Cash Flow. We target a Maintenance Reinvestment Rate of less than 45% and an Upstream Reinvestment Rate of less than

50%. We are focused on our goal of maintaining a conservative financial profile, with a long-term Total Net Leverage Ratio target of 1.0x to 1.5x. Although we may allow our leverage ratio to exceed our target in connection with a strategic acquisition, we would seek to return our leverage level to between 1.0x and 1.5x as soon as reasonably possible thereafter through Adjusted Free Cash Flow and, if needed, reduced activity levels. To support the generation of future Adjusted Free Cash Flow, we have a policy of hedging approximately 25% to 60% of our forecasted production volumes over a given 12 to 48-month period, subject to maintaining compliance with the hedging requirements in the RBL Credit Agreement. We believe our capital efficient project inventory, low-decline natural gas production and multiple, integrated business lines will provide consistent returns through varying business cycles. We intend to apply our cash flows to manage our indebtedness in line with our leverage target, fund our capital expenditure program, enhance stockholder value and execute opportunistic acquisitions across our four business lines. Adjusted EBITDAX is not a financial measure calculated in accordance with GAAP. See "*— Summary Historical Financial Information — Non-GAAP Financial Measures*" for a description of this measure and a reconciliation to the most directly comparable GAAP measure.

- **Focus on our net zero objectives.** We seek to apply our integrated business model, CCUS projects and carbon-negative initiatives to realize Scope 1 and 2 net zero emissions from our owned and operated upstream and natural gas midstream businesses by the early 2030s. We believe we can achieve this through reductions in and offsets to our owned and operated upstream and natural gas midstream emissions from our "Pad of the Future" emissions reductions program and emissions monitoring and leak surveys, the retirement of SRECs generated by the BKV-BPP Power Joint Venture's planned solar facility and executing CCUS projects. We believe that carbon emissions within the United States can be reduced substantially through carbon capture on natural gas production, power plants, processing facilities and other energy and industrial infrastructure. As such, in addition to lowering emissions in our owned and operated upstream and natural gas midstream businesses, CCUS for third parties has become a focus of our business plan. We expect our CCUS projects to represent a meaningful portion of our budgeted capital expenditures going forward as we advance our long-term goal of offsetting Scope 3 emissions from our owned and operated upstream and natural gas midstream businesses.
- **Encourage innovation.** Our distinctive culture encourages innovation with a value-driven focus that feeds into our competitive advantage. For example, our emphasis on the efficient application of modern technology led to the development of our "Pad of the Future" program, our advancements in Barnett refracs and other operational improvements. We intend to continue to develop, retain and add to our already talented, experienced and forward-thinking employees. Our unified team and mantra of "Being a force for good" underpin our core values and provides us with confidence in our ability to successfully manage and grow our business.
- **Deliver robust returns to stockholders.** We intend to prioritize delivering strong returns to our stockholders through our focus on creating stockholder value. We believe our operational expertise in successfully drilling and refracturing wells, acquiring and integrating assets purchased at attractive valuations and maintaining financial discipline will underpin our ability to meet our stockholder return goals. Our integrated businesses and natural gas-weighted, low-decline PDP reserves collectively reduce our downside risk while providing asymmetric upside returns from the confluence of commodity price uplift potential, operational improvement and development opportunities, and future accretive acquisition opportunities. See "*Risk Factors — Risks Related to the Offering and Our Common Stock*."

Competitive Strengths

We have a number of strengths that we believe will help us successfully execute our business strategy, including:

- **Integrated asset base well positioned for sustainable growth.** Our upstream, midstream and power asset bases reside in geographically concentrated areas with numerous asset acquisition opportunities in close proximity. Our proven ability to successfully negotiate, close and integrate these acquisition opportunities quickly and cost effectively will allow us to continue to grow our portfolio of assets synergistically. We believe that scale and the continued application of technological developments and operational excellence, combined with stable, low-decline production profiles, will continue to generate significant capital efficient development opportunities in the Barnett and NEPA.

- **High quality, low decline assets serving key demand markets.** Through a series of accretive acquisitions, we have established an extensive and largely contiguous acreage position in two key markets, the Barnett and NEPA. Our Barnett assets cover approximately 460,000 net acres, with an approximately 80.2% Effective NRI, and are located in close proximity to key Gulf Coast industrial and LNG demand centers. Our NEPA assets consist of approximately 19,480 net acres (after giving effect to the sales of BKV Chaffee and certain assets held by BKV Chelsea) in one of the most prolific parts of the Marcellus Shale and are located within less than 200 miles to key demand markets in the U.S. Northeast. We believe the geologic, operational and engineering risks associated with our leasehold acreage have been significantly mitigated through historical development activity. Our PDP reserves had an estimated 8.1% year-over-year average base decline rate over the next 10 years as of December 31, 2023. Additionally, we have an inventory of over 15 years of refrac and new drill locations within our core acreage that give us the flexibility to maintain or slightly grow current production levels, depending on the commodity cycle.

- **Lower emissions energy production.** We are focused on achieving Scope 1 and 2 net zero emissions from our owned and operated upstream and natural gas midstream businesses by the early 2030s. We believe we have a comprehensive ESG program, which is overseen and directed by an executive ESG steering committee. In February 2023, we re-certified most of our production under the TrustWell environmental assessment program of Project Canary, an environmental certification and ESG data company. We achieved a Gold rating from Project Canary, the second highest rating a company can receive for its production, qualifying the certified portion of our natural gas production as RSG. As part of its environmental assessment, Project Canary analyzes and certifies our production on a well by well basis. As of June 30, 2024, approximately 70% of our NEPA production and approximately 45% of our Barnett production was re-certified. We intend to continue an environmental assessment of substantially all of our existing production. In addition, we intend to advance the market for our produced gas beyond RSG and its current certification towards Carbon Sequestered Gas, a Scope 1, 2 and 3 carbon neutral natural gas product. We expect that production of Carbon Sequestered Gas will be achieved by bundling RSG with carbon credits sufficient to offset the estimated emissions associated with the production, gathering and boosting of such RSG, as well as the estimated emissions from its transmission, distribution (if applicable) and ultimate combustion, with the quantified emissions and the requisite volume of CCUS offsets being third-party certified. We have an agreement with a third party to establish the blockchain ledger and tokens; however, this process is dependent upon the development of the necessary technology by such third party. In addition, we expect to utilize the blockchain ledger and tokens with the American Carbon Registry, once that registry has been established. The carbon credits included in our Carbon Sequestered Gas will be generated by our CCUS projects, as described in "*— Overview — Our Operations — Path to Net Zero Emissions,*" and retired against our Scope 1 and/or Scope 3 emissions. We believe Carbon Sequestered Gas could potentially provide a decarbonized, certified and qualified fuel and retired credits bundle that is a differentiated and premium product. Additionally, we have a plan to achieve net zero Scope 1 and 2 emissions from our owned and operated upstream and natural gas midstream businesses by the early 2030s based on our "Pad of the Future" program, emissions monitoring and leak surveys and the retirement of SRECs generated by the BKV-BPP Power Joint Venture's planned solar facility and executing CCUS projects. However, if we are not able to complete CCUS projects having sufficient sequestration volumes of CO_2 on this timeline, we may consider alternatives to offset the Scope 1 and Scope 2 emissions from our owned and operated upstream and natural gas midstream businesses (including the purchase of verified offset credits from the BKV-BPP Power Joint Venture or third parties). Ultimately, we may not be able to achieve this goal, produce Carbon Sequestered Gas or obtain a premium on such gas (particularly to the extent there are any concerns regarding the type, ownership or quality of offsets or other environmental attributes used for our characterization of Carbon Sequestered Gas).

- **Efficient use of capital.** Our deep, high-graded inventory of refrac opportunities coupled with our inventory of new drill locations allow us to create meaningful additional cash flow with comparatively modest additional capital investments. We utilize operational improvements such as operational process and procurement efficiencies, use of existing field infrastructure, innovative and cost-effective refrac techniques and designs (including diversion methods), drilling long laterals in the Barnett, and optimizing available midstream capacity to further maximize our capital efficiency. Through our midstream, power and CCUS business lines, we are capturing margin across the value chain.

- **Well capitalized and conservative balance sheet.** Following the completion of this offering, we intend to continue to maintain a strong balance sheet and fund our upstream, midstream and power operations predominantly with internally generated cash flows. We believe that the low decline, predictable nature of our upstream production profile, combined with our hedging plan and reinvestment rate targets, will allow us to successfully meet our leverage goals.
- **High caliber and proven management team.** We maintain a highly experienced and knowledgeable management team with an average of over 25 years of experience among our senior management team. Our leadership team has significant experience managing integrated energy and power assets for large-scale enterprises, including companies such as PTT Exploration and Production Public Company Limited ("PTT Exploration") and BP p.l.c. ("BP"). Furthermore, our sponsor, Banpu, one of Asia Pacific's largest integrated energy companies, provides us with unique and valuable insights into optimizing our integrated energy business.

Recent Developments

Dispositions

- **Sales of BKV Chaffee and BKV Chelsea Assets**. On June 14, 2024, we sold our wholly owned subsidiary, BKV Chaffee, which owned a non-operated interest in approximately 9,800 net acres and 116 gross (24.2 net) wells and 122 Bcfe of proved reserves in NEPA, as well as our interest in the Repsol Oil & Gas operated midstream system, for a purchase price of $106.7 million, subject to adjustment. On June 28, 2024, our wholly owned subsidiary, BKV Chelsea, sold certain of its non-operated upstream assets, including its interest in approximately 6,800 net acres and 214 gross (15.4 net) wells and 35 Bcfe of proved reserves in NEPA for a purchase price of $25.0 million, subject to adjustment.

Credit Facilities

- **Refinancing.** On June 11, 2024, the amounts outstanding under the Term Loan Credit Agreement, the Revolving Credit Agreement and the SCB Credit Facility (each as defined herein) were paid off with proceeds from the loans under the RBL Credit Agreement and cash on hand. The Term Loan Credit Agreement, the Revolving Credit Agreement and the SCB Credit Facility were terminated concurrently with the repayment of the remaining amounts owed thereunder. See "*Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Loan Agreements and Credit Facilities*" for additional information regarding our loan agreements and credit facilities.
- **RBL Credit Agreement**. On June 11, 2024, BKV Corporation, as guarantor, and the RBL Borrower, as borrower, entered into the RBL Credit Agreement, a reserve-based credit agreement with Citibank, N.A., as administrative agent, and the financial institutions party thereto. The RBL Credit Agreement has a maximum credit commitment of $1.5 billion. As of June 11, 2024, the RBL Credit Agreement has a borrowing base of $800.0 million and an elected commitment of $600.0 million. The RBL Credit Agreement includes a $50.0 million sublimit for the issuance of letters of credit. As of August 12, 2024, $360.0 million of revolving borrowings and $16.6 million of letters of credit were outstanding under the RBL Credit Agreement, leaving $223.4 million of available capacity thereunder for future borrowings and letters of credit. The borrowing base is subject to semi-annual redeterminations based upon the value of our oil and gas properties as determined in a reserve report. The reserve report will be dated as of January and July of each year with the January reserve report prepared by a third-party engineer and the July report prepared by our internal engineers. The borrowing base is also subject to reduction in connection with certain dispositions of assets. The RBL Credit Agreement requires that the RBL Borrower and its restricted

subsidiaries provide a first-priority security interest in their oil and gas properties (such that those properties subject to the security interest represent at least 90% of PV-9 (as defined in the RBL Credit Agreement) of their borrowing base properties) and substantially all of the personal property assets, subject to customary exceptions, of BKV Corporation, the RBL Borrower, and its restricted subsidiaries that are guarantors thereunder. The RBL Credit Agreement is scheduled to mature on June 12, 2028. The RBL Credit Agreement includes usual and customary covenants for facilities of its type and size. The covenants cover matters such as mandatory reserve reports, the responsible operation and maintenance of properties, certifications of compliance and required disclosures to the lenders. It also places limitations on the incurrence by the RBL Borrower and its restricted subsidiaries of additional indebtedness and liens, declaring or making restricted payments (including dividends and distributions), making investments, designating unrestricted subsidiaries, operating outside the United States, entering into mergers, sales of assets outside the ordinary course of business, transactions with affiliates and limitations on the amount of commodity and interest rate hedges that can be put in place. Such limitations do not apply to BKV Corporation or, unless and until such time such entities become restricted subsidiaries pursuant to the RBL Credit Agreement, BKV dCarbon Ventures, LLC and BKV-BPP Power LLC. The RBL Credit Agreement also contains financial maintenance covenants requiring the RBL Borrower to maintain a net leverage ratio of no greater than 3.25 to 1.00 and a current ratio of at least 1.00 to 1.00. Amounts outstanding under the RBL Credit Agreement bear interest based upon SOFR or ABR (each as defined in the RBL Credit Agreement), as applicable, plus an additional margin which is based on the percentage of the borrowing base being utilized, ranging from 2.75% to 3.75% for SOFR loans and 1.75% to 2.75% for ABR loans. There is also a commitment fee of 0.50% on the undrawn commitments. Obligations under the RBL Credit Agreement may be prepaid without premium or penalty, other than customary breakage costs. See "*Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Loan Agreements and Credit Facilities*" for additional information regarding the RBL Credit Agreement and the covenants contained therein.

Corporate Values, Management Team and Sponsor

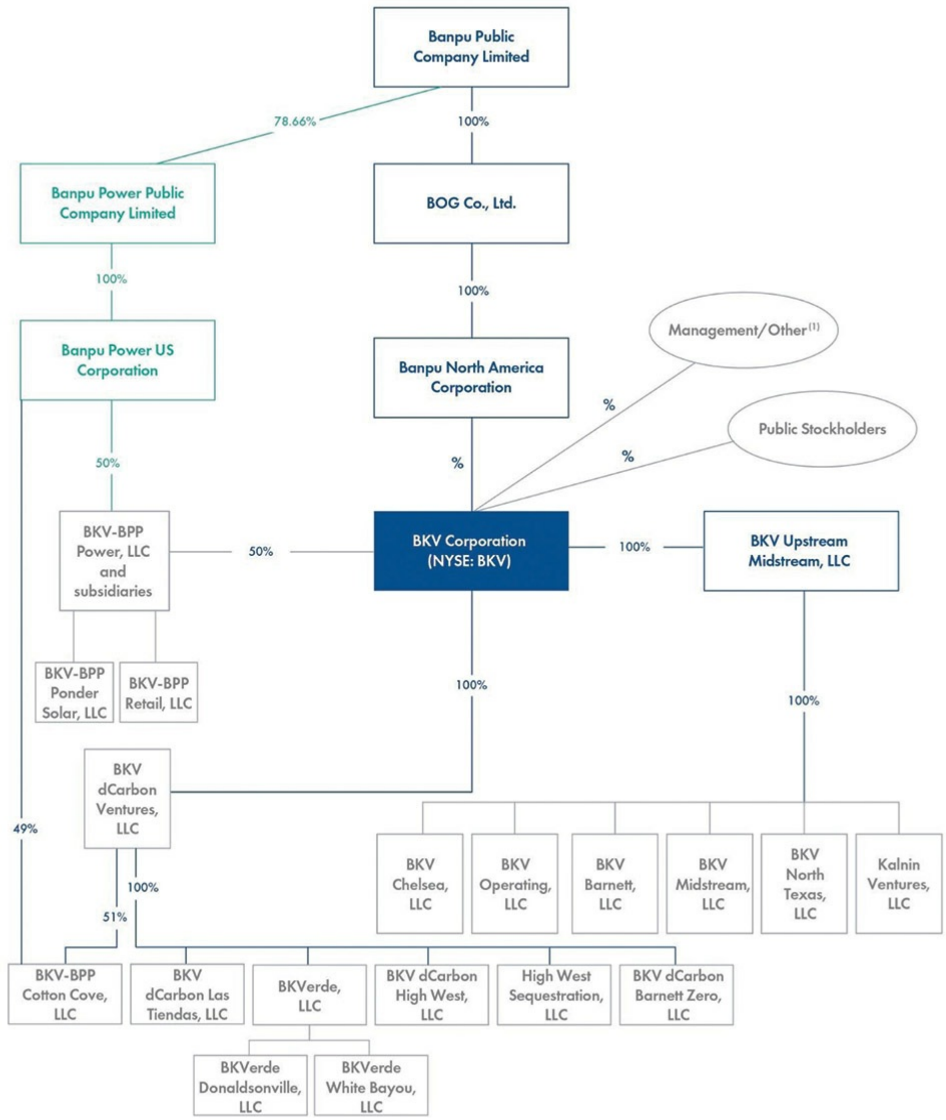
The following corporate values underpin our corporate culture and decision-making: Deliver on Promises, Have Grit, Embrace Change, Show Courage, Solve Problems, Do Good and Be One BKV.

Our management team is led by our Chief Executive Officer and founder, Christopher P. Kalnin, who has approximately 23 years of experience in exploration and production ("E&P") (PTT Exploration & Production), management consulting (McKinsey & Company) and finance (Credit Suisse First Boston). Eric Jacobsen serves as our Chief Operating Officer with over 29 years of energy operational experience, including 11 years of experience in shale, 16 years of experience at BP and its predecessors and six years of experience at Noble Energy, Inc. John Jimenez serves as our Chief Financial Officer with over 31 years of international energy experience working with BP and Reliance Industries Limited.

BNAC, our majority stockholder, is an indirect, wholly owned subsidiary of Banpu, our ultimate parent company. Banpu is a multi-billion U.S. dollar market cap energy company publicly traded in Thailand. With four decades of experience in business operations covering 10 countries across the Pacific Rim region and the United States, Banpu is an international versatile energy provider committed to its Greener & Smarter strategy, which prioritizes environmentally sustainable businesses and leverages smart technologies and innovations. Upon completion of this offering, Banpu will beneficially own approximately % of our common stock (or approximately % if the underwriters exercise in full their option to purchase additional shares of our common stock). Banpu has informed us that although it may reduce a portion of its ownership position over time, it intends to remain a long-term stockholder and supporter of BKV. If, after this initial public offering, any person or group (other than Banpu and its controlled affiliates, excluding portfolio companies and operating companies) acquires 35% or more of our equity interests, or if any person or group acquires a greater percentage of our equity interests than are then held by Banpu and its controlled affiliates (excluding portfolio companies and operating companies of Banpu), such event will be an event of default under the RBL Credit Agreement. See "*Risk Factors — Risks Related to Our Relationship with Banpu and its Affiliates*."

Our Structure

The chart below displays a summary of our ownership structure after giving effect to this offering.



(1) Consists of management, directors and other employee and non-employee stockholders.

The information in the chart above does not include 5,000,000 additional shares of our common stock reserved for awards pursuant to the 2022 Plan, including shares of common stock that may be issued upon vesting of equity awards that we expect to be granted in connection with this offering, or 500,000 shares of our common stock available for purchase by employees pursuant to the ESPP.

Implications of Being an Emerging Growth Company

We qualify as an "emerging growth company" as defined in Section 2(a)(19) of the Securities Act of 1933, as amended (the "Securities Act"), including as modified by the Jumpstart Our Business Startups Act of 2012 (the "JOBS Act"). As a result, for so long as we qualify as an emerging growth company, we are eligible to take advantage of certain exemptions from various reporting requirements applicable to other public companies that are not emerging growth companies. These exemptions include:

- being permitted to present only two years of audited financial statements and only two years of related "*Management's Discussion and Analysis of Financial Condition and Results of Operations*" in this prospectus;
- not being required to comply with the auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act of 2002, as amended (the "Sarbanes-Oxley Act");
- reduced disclosure obligations regarding executive compensation in our periodic reports, proxy statements and registration statements, including in this prospectus;
- not being required to comply with any new requirements adopted by the Public Company Accounting Oversight Board ("PCAOB") requiring a supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer; and
- exemptions from the requirements of holding a nonbinding advisory vote on executive compensation and stockholder approval of any golden parachute payments not previously approved.

We have elected to take advantage of certain of the reduced disclosure obligations in this prospectus and may elect to take advantage of other reduced reporting requirements in our future filings with the Securities and Exchange Commission (the "SEC"). As a result, the information that we provide to our stockholders may be different than you might receive from other public reporting companies in which you hold equity interests.

The JOBS Act also provides that an emerging growth company can take advantage of an extended transition period for complying with new or revised accounting standards, but we have irrevocably elected not to avail ourselves of this exemption. Rather, we will adopt new or revised accounting standards on the relevant dates in which adoption of such standards is required for other public companies.

We may take advantage of these provisions until the last day of our fiscal year following the fifth anniversary of the date of the first sale of our common equity securities pursuant to an effective registration statement under the Securities Act. Such fifth anniversary will occur in 2029. However, if certain events occur prior to the end of such five-year period, including if we become a "large accelerated filer," our gross revenues for any fiscal year equal or exceed \$1.235 billion or we issue more than \$1.0 billion of non-convertible debt in any three-year period, we will cease to be an emerging growth company prior to the end of such five-year period.

Controlled Company

We have applied to list our common stock on the NYSE under the symbol "BKV." Upon completion of this offering, BNAC will hold approximately % of our total outstanding shares of common stock (or approximately % if the underwriters exercise in full their option to purchase additional shares), comprising more than 50% of the voting power of our outstanding common stock. As a result, we will be a "controlled company" within the meaning of the corporate governance rules of the NYSE. As a "controlled company," we will be eligible to rely on exemptions from the obligation to comply with certain NYSE corporate governance requirements, including the requirements that:

- a majority of our board of directors consist of independent directors;
- we have a corporate governance and nominating committee that is composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities; and
- we have a compensation committee that is composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities.

These exemptions do not modify the independence requirements for our audit committee. As a controlled company, we will remain subject to the rules of the Sarbanes-Oxley Act and the NYSE that require us to have an audit committee composed entirely of independent directors. Under these rules, we must have at least one independent director on our audit committee by the date our common stock is listed on the NYSE, at least two independent directors on our audit committee within 90 days of the listing date, and at least three independent directors on our audit committee within one year of the listing date. We expect to have four independent directors upon the closing of this offering.

While BNAC continues to control more than 50% of the voting power of our outstanding common stock, we qualify for, and intend to rely on, these exemptions. Accordingly, you will not have the same protections afforded to stockholders of companies that are subject to all of the corporate governance requirements of the NYSE.

If we cease to be a controlled company within the meaning of the applicable rules of the NYSE, we will be required to comply with these requirements after specified transition periods.

Contact Information

Our principal executive offices are located at 1200 17th Street, Suite 2100, Denver, Colorado 80202, and our telephone number at such address is (720) 375-9680. Our website address is *www.bkvcorp.com*. The contents of our website are not incorporated by reference herein and are not a part of, and shall not deemed to be a part of, this prospectus.

The Offering

Issuer	BKV Corporation, a Delaware corporation
Securities offered	Common stock, par value $0.01 per share (“common stock”)
Common stock offered by us	shares (or shares if the underwriters exercise in full their option to purchase additional shares)
Underwriters’ option to purchase additional shares	The underwriters have an option for a period of 30 days to purchase up to an additional shares of our common stock.
Common stock outstanding immediately after this offering	shares (or shares if the underwriters exercise in full their option to purchase additional shares)
Use of proceeds	We estimate that the net proceeds to us from the sale of our common stock in this offering, after deducting underwriting discounts and commissions and estimated offering expenses payable by us, will be approximately $ million (or approximately $ million if the underwriters exercise in full their option to purchase additional shares), based on an assumed initial public offering price of $ per share (the midpoint of the price range set forth on the cover page of this prospectus). Of the net proceeds we receive from the sale of our common stock in this offering, we intend to use approximately $ million to repay certain indebtedness, which may include some or all of the $50.0 million in aggregate principal amount outstanding under the BNAC A&R Loan Agreement and the outstanding revolving borrowings under the RBL Credit Agreement, for growth capital expenditures and for other general corporate purposes, which may include the expansion of our CCUS business. See “*Use of Proceeds.*”
Dividend policy	We currently do not pay a fixed cash dividend to holders of our common stock, and certain of our debt agreements place certain restrictions on our ability to pay cash dividends to holders of our common stock. Our dividend policy is under consideration by our board of directors. Any future determination related to our dividend policy will be made at the sole discretion of our board of directors. See “*Dividend Policy.*”
Voting rights	Each share of common stock will entitle the holder to one vote per share. Generally, matters to be voted on by stockholders must be approved by a majority of the votes entitled to be cast at a meeting by holders of all shares of common stock present in person or represented by proxy. In addition, pursuant to the stockholders’ agreement to be entered into upon the completion of this offering between BNAC and us (our “Stockholders’ Agreement”), for so long as BNAC and Banpu beneficially own 10% or more of our voting stock, BNAC will be entitled to designate for nomination to our board of directors a number of individuals approximately proportionate to such beneficial ownership, provided that

	(i) from the completion of this offering until the first anniversary of the completion of this offering, at least three board seats will not be BNAC designees, (ii) from and after the first anniversary of the completion of this offering until the first date on which BNAC and Banpu beneficially own 50% or less of our voting stock, at least four board seats will not be BNAC designees, and (iii) from and after the first date on which BNAC and Banpu beneficially own 50% or less of our voting stock, a number of board seats equal to the minimum number of directors that would constitute a majority of the total number of directors comprising our board of directors will not be BNAC designees. See "*Management*," "*Principal Stockholders*," "*Description of Capital Stock*" and "*Certain Relationships and Related Party Transactions*" for additional information.
Risk factors	You should read the section of this prospectus titled "*Risk Factors*" and other information included in this prospectus for a discussion of factors to carefully consider before deciding to invest in shares of our common stock.
Controlled company	We will be a "controlled company" within the meaning of the corporate governance rules of the NYSE. Upon completion of this offering, BNAC will hold % of our common stock (or approximately % if the underwriters exercise in full their option to purchase additional shares), comprising more than 50% of the voting power of our outstanding common stock. See "*Management — Controlled Company*."
Listing and stock exchange symbol	We have applied to list our common stock on the NYSE under the symbol "BKV."
Reserved Share Program	At our request, an affiliate of Citigroup Global Markets Inc., a participating underwriter, has reserved for sale, at the initial public offering price, up to 5% of the shares of common stock being offered by this prospectus for sale to some of our directors, executive officers, employees, business associates and related persons at the public offering price. If these persons purchase reserved shares, it will reduce the number of shares of common stock available for sale to the general public. Any reserved shares that are not so purchased will be offered by the underwriters to the general public on the same terms as the other shares offered by this prospectus. These persons must commit to purchase no later than the close of business on the day following the date of this prospectus. Any participants purchasing such reserved common stock will be prohibited from selling such stock for a period of 180 days after the date of this prospectus. See "*Principal Stockholders*" for more information.

The number of shares of common stock that will be outstanding immediately after the completion of this offering is based on shares of our common stock to be issued pursuant to this offering (assuming the underwriters do not exercise their option to purchase additional shares) and excludes 5,000,000 additional shares of our common stock reserved for awards pursuant to the 2022 Plan, including shares of common stock that may be issued upon vesting of equity awards that we expect to be granted in connection with this offering, and 500,000 shares of our common stock available for purchase by employees pursuant to the ESPP, which will become effective upon the completion of this offering.

Unless otherwise indicated, the information in this prospectus:

- assumes the execution of our Stockholders' Agreement, as further described under "*Certain Relationships and Related Party Transactions*";
- reflects the October 2023 one-for-two reverse stock split;
- assumes the amendment and restatement of our existing certificate of incorporation and the amendment and restatement of our existing bylaws in connection with the consummation of the offering;
- assumes an initial public offering price of $ per share of common stock (the midpoint of the price range set forth on the cover page of this prospectus);
- assumes that the underwriters do not exercise their option to purchase additional shares of common stock; and
- excludes shares of common stock that directors and executive officers may purchase through the reserved share program.

Risk Factors Summary

Investing in our common stock involves risks, including those highlighted in the section titled "*Risk Factors*" immediately following this prospectus summary, of which you should be aware before making a decision to invest in our common stock. These risks may offset our competitive strengths or have a negative effect on our strategy or operating activities, which could cause a decrease in the price of our common stock and a loss of all or part of your investment. These risks include, among others, the following:

Risks Related to Our Upstream Business and Industry

- the volatility of natural gas and NGL prices due to factors beyond our control;
- our reliance on a single third party for all of our natural gas marketing and another third party for substantially all of our natural gas and NGL midstream services with respect to the Barnett assets we acquired from Devon Energy;
- our reserves estimates are based on assumptions that may prove to be inaccurate;
- our ability to find or acquire additional natural gas and NGL reserves that are economically recoverable, including development of our proved undeveloped reserves and associated capital expenditures;
- uncertainties in evaluating the expected benefits and potential liabilities of recoverable reserves;
- risks and uncertainties related to drilling operations, which are high-risk and operationally complex;
- the availability or cost of water, equipment, supplies, personnel and oilfield services;
- our limited control over activities on properties we do not operate;

Risks Related to Our Power Generation Business

- extreme weather, transmission congestion and changes to the regulatory environment;
- the operation of our power generation business through a joint venture which we do not control;
- risks and hazards related to the operation or maintenance of electric generation facilities, including disruption of the fuel supplies necessary to generate power at the Temple Plants;
- the lack of long-term power sales agreements for the Temple Plants;

Risks Related to Our Retail Power Business

- the operation of our retail power business through a joint venture which we do not control;

- our ability to attract and retain customers in the competitive retail power marketplace;
- market price risk and changes in law, regulation or market structure resulting in unanticipated costs;
- our ability to maintain our retail electric provider certification;

Risks Related to Our CCUS Business

- our ability to successfully pursue and develop our CCUS business, the associated material capital investments and any changes to financial and tax incentives;

Risks Related to Our Midstream Business

- risks and hazards related to midstream operations as complex activities;
- our dependence on our natural gas midstream system;

Risks Related to Our Business Generally

- the geographical concentration of substantially all of our oil and gas and midstream properties;
- the effect of a deterioration in general economic, business or industry conditions;
- our ability to achieve our near term and long term net zero goals on our anticipated time frame;
- our ability to generate cash flow to meet our debt obligations or fund our other liquidity needs;
- events of default if we are unable to comply with restrictions in our debt agreements (including if after this offering, any person or group (other than Banpu and its controlled affiliates, excluding portfolio companies and operating companies) acquires 35% or more of our equity interests, or if any person or group acquires a greater percentage of our equity interests than are then held by Banpu and its controlled affiliates (excluding portfolio companies and operating companies of Banpu);
- risks related to our debt and debt agreements and hedging arrangements that expose us to risk of financial losses and counterparty credit risk;
- our dependence, as a holding company, on our subsidiaries and our joint venture for cash;
- operating hazards that could result in substantial losses or liabilities for which we may not have adequate insurance coverage;
- our ability to make accretive acquisitions or successfully integrate acquired businesses or assets;
- our substantial capital requirements and our ability to obtain financing or fund working capital needs;
- the intense competition in the energy industry and our ability to compete with other companies;
- cybersecurity or physical security threats or disruptions or loss of our information systems;
- increased activism and negative investor sentiment regarding upstream activities and companies;
- the loss of our executive officers and technical personnel and our ability to retain technical personnel;
- exemptions from certain reporting requirements for as long as we are an emerging growth company;

Risks Related to Environmental, Legal Compliance and Regulatory Matters

- complex laws, regulations and initiatives related to our operations and the use of hydraulic fracturing;
- the effect of increased attention to ESG matters and environmental conservation measures;
- reductions in demand for natural gas, NGL and oil;
- risks related to climate change, including transitional, legal, political, financial and physical risks;
- significant costs and liabilities related to environmental, health and safety laws and regulations;

- potential tax law changes;
- complex and evolving laws and regulations regarding privacy and data protection;

Risks Related to Our Relationship with Banpu and its Affiliates

- the substantial influence of Banpu, our controlling stockholder, over us;
- our historical reliance on Banpu for capital investments to fund our business operations;
- we expect to be a "controlled company" within the meaning of the NYSE rules and, as a result, will qualify for and could rely on exemptions from certain corporate governance requirements;
- conflicts of interest between Banpu and us or our other stockholders or conflicts of interest of our officers and/or directors as a result of their positions with, or ownership of common stock of, Banpu;

Risks Related to the Offering and Our Common Stock

- our actual operating results and activities could differ materially from our estimates;
- the impact of our lack of dividend payments on the market price of our common stock;
- the costs of, and our ability to comply with, the requirements of being a public company;
- we have identified material weaknesses in our internal control over financial reporting;
- the lack of an existing market for our common stock;
- provisions in our governing documents and Delaware law that could discourage acquisition bids or merger proposals; and
- future sales of our common stock in the public market, or the perception that such sales may occur, could reduce our stock price.

Summary Historical Financial Information

The following table shows our summary historical consolidated financial information for the periods and as of the dates indicated. The summary historical consolidated financial information as of and for the six months ended June 30, 2024 and 2023 was derived from our unaudited historical condensed consolidated financial statements, included elsewhere in this prospectus. The summary historical consolidated financial information as of and for the years ended December 31, 2023, 2022 and 2021 was derived from our audited historical consolidated financial statements, included elsewhere in this prospectus.

The summary financial data is qualified in its entirety by, and should be read in conjunction with, "*Management's Discussion and Analysis of Financial Condition and Results of Operations*" included elsewhere in this prospectus, as well as our historical consolidated financial statements and related notes, and other financial information included in this prospectus. Historical results are not necessarily indicative of results that may be expected for any future period.

	Six Months Ended June 30,		Year Ended December 31,		
	2024	2023	2023	2022	2021
	(in thousands, except per share amounts)				
Revenues and other operating income					
Natural gas revenues	$ 179,175	$ 257,032	$ 509,846	$ 1,310,339	$ 597,050
NGL revenues	84,632	91,477	187,860	311,542	225,135
Oil revenues	3,734	4,398	8,445	11,866	7,560
Natural gas, NGL, and oil revenues	267,541	352,907	706,151	1,633,747	829,745
Midstream revenues	7,506	8,428	16,168	12,676	6,917
Derivative gains (losses), net	(11,165)	116,947	238,743	(629,701)	(383,847)
Marketing revenues	6,967	4,732	8,710	11,001	52,616
Gain on sale of assets	6,784	339	—	—	—
Related party and other	10,479	3,314	8,251	2,799	251
Total revenues and other operating income	288,112	486,667	978,023	1,030,522	505,682
Operating expenses					
Lease operating and workover	68,640	80,723	150,647	131,497	86,831
Taxes other than income	21,215	41,496	72,290	114,668	45,650
Gathering and transportation	113,105	120,586	248,990	208,758	173,587
Depreciation, depletion, amortization, and accretion[(1)]	111,479	78,354	223,370	118,909	92,277
General and administrative	39,941	52,488	114,688	148,559	85,740
Other	11,276	8,483	12,625	3,567	1,274
Total operating expenses	365,656	382,130	822,610	725,958	485,359
Income (loss) from operations	(77,544)	104,537	155,413	304,564	20,323
Other income (expense)					
Bargain purchase gain	—	—	—	170,853	—
Gain on settlement of litigation	—	—	—	16,866	—
Gains (losses) on contingent consideration[(2)]	6,070	22,910	38,375	6,632	(194,968)
Earnings (losses) from equity affiliate	(22,960)	(14,275)	16,865	8,493	910
Loss on debt extinguishment	(13,877)	—	—	—	—
Interest income	3,404	1,136	3,138	1,143	8
Interest expense	(31,246)	(34,377)	(69,942)	(26,322)	—
Interest expense, related party	(3,852)	(3,083)	(7,078)	(10,846)	(2,134)
Other income	350	1,851	8,372	1,411	872
Income (loss) before income taxes	(139,655)	78,699	145,143	472,794	(174,989)
Income tax benefit (expense)	41,373	(17,885)	(28,225)	(62,652)	40,526
Net income (loss) attributable to BKV Corporation	(98,282)	60,814	116,918	410,142	(134,463)

	Six Months Ended June 30,		Year Ended December 31,		
	2024	2023	2023	2022	2021
	(in thousands, except per share amounts)				
Less accretion of preferred stock to redemption value	—	—	—	—	(3,745)
Less preferred stock dividends	—	—	—	—	(9,900)
Less deemed dividend on redemption of preferred stock	—	—	—	—	(22,606)
Net income (loss) attributable to common stockholders	(98,282)	60,814	116,918	410,142	(170,714)
Net income (loss) per common share[3]					
Basic	$ (1.48)	$ 1.03	$ 1.93	$ 6.99	$ (2.92)
Diluted	$ (1.48)	$ 0.97	$ 1.82	$ 6.62	$ (2.92)
Weighted average number of common shares outstanding[3]					
Basic	66,318	58,779	60,730	58,659	58,496
Diluted	66,318	62,434	64,380	61,990	58,496
Balance sheet information (at period end):					
Cash and cash equivalents	$ 9,197	$ 22,421	$ 25,407	$ 153,128	$ 134,667
Restricted cash[4]	$ —	$ —	$ 139,662	$ —	$ —
Total natural gas properties, net	$1,911,235	$2,237,870	$2,125,442	$2,209,518	$1,176,117
Total assets	$2,247,510	$2,503,242	$2,683,146	$2,702,573	$1,620,828
Total liabilities	$ 858,480	$1,239,558	$1,197,979	$1,506,649	$ 865,889
Total mezzanine equity	$ 189,888	$ 142,149	$ 186,954	$ 151,883	$ 83,847
Total stockholders' equity	$1,199,142	$1,121,535	$1,298,213	$1,044,041	$ 671,092
Statement of cash flows information					
Net cash provided by operating activities	$ 9,782	$ 80,924	$ 123,076	$ 349,194	$ 358,133
Net cash provided by (used in) investing activities	$ 101,633	$ (128,606)	$ (177,848)	$ (865,566)	$ (161,858)
Net cash provided by (used in) financing activities	$ (267,287)	$ (83,025)	$ 66,713	$ 534,833	$ (79,053)
Other financial data (unaudited)[5]					
Adjusted EBITDAX	$ 108,837	$ 117,045	$ 251,158	$ 575,504	$ 281,024
Upstream capital expenditures (accrued)[6]	$ 25,528	$ 91,522	$ 107,544	$ 253,179	$ 77,634
Upstream Reinvestment Rate[6]	23%	78%	43%	44%	28%
Adjusted Free Cash Flow	$ 67,055	$ (11,389)	$ 19,132	$ 169,213	$ 165,090
Adjusted Free Cash Flow Margin	22%	(3)%	3%	10%	19%
Total Net Leverage Ratio	1.84x	2.69x	1.95x	1.00x	0.11x

(1) Includes accretion of lease liabilities related to office space and compressor leases.

(2) Represents contingent consideration liabilities as of the dates set forth above accruing as an earnout obligation under the terms of our purchase agreements with Devon Energy and ExxonMobil Corporation for the purchase of our 2020 Barnett Assets and 2022 Barnett Assets, respectively. Contingent consideration is stated at fair value on our condensed consolidated balance sheets, with changes in fair value recorded in the condensed consolidated statements of operations.

(3) Per share data gives effect to the October 2023 one-for-two reverse stock split.

(4) As of December 31, 2023, the restricted cash balance represents cash to fund our debt service reserve in accordance with the Term Loan Credit Agreement.

(5) Adjusted EBITDAX and Adjusted Free Cash Flow are not financial measures calculated in accordance with GAAP. See "— *Non-GAAP Financial Measures*" for how we define each of these measures and a reconciliation to the most directly comparable GAAP measures. In addition, we define Upstream Reinvestment Rate as total capital expenditures accrued for the development of natural gas properties during the period (excluding leasehold costs and acquisitions) as a percentage of Adjusted EBITDAX for

the same period, and we define Adjusted Free Cash Flow Margin as the ratio of Adjusted Free Cash Flow to total revenues excluding derivative gains and losses. Total Net Leverage Ratio represents the ratio of total debt less cash and cash equivalents to Adjusted EBITDAX.

(6) Upstream capital expenditures (accrued) for the six months ended June 30, 2024 includes $4.0 million of net cash not yet paid as of June 30, 2024 for capital expenditures incurred and accrued during the period. Upstream capital expenditures (accrued) for the six months ended June 30, 2023 and for the year ended December 31, 2023 does not include $21.6 million and $26.9 million, respectively, of net cash paid in 2023 for capital expenditures incurred and accrued during the year ended December 31, 2022. Upstream capital expenditures (accrued) for the years ended December 31, 2022 and 2021 includes $17.8 million and $13.7 million, respectively, of net cash paid in subsequent periods for capital expenditures incurred and accrued during the respective period presented. For a reconciliation of upstream capital expenditures (accrued) to cash flows used in development of natural gas properties in the condensed consolidated statements of cash flows, see "*Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Capital Resources — Cash flows used in investing activities*."

Non-GAAP Financial Measures

Adjusted EBITDAX

We define Adjusted EBITDAX as net income (loss) attributable to BKV Corporation before (i) non-cash derivative gains (losses), (ii) depreciation, depletion, amortization and accretion, (iii) exploration and impairment expense, (iv) gains (losses) on contingent consideration liabilities, (v) interest expense, (vi) interest expense, related party, (vii) income tax benefit (expense), (viii) equity-based compensation expense, (ix) bargain purchase gains, (x) earnings or losses from equity affiliate, (xi) the portion of settlements paid (received) for early-terminated derivative contracts that relate to future periods and (xii) other nonrecurring transactions. Adjusted EBITDAX is a supplemental non-GAAP financial measure that is used by our management and external users of our consolidated financial statements, such as industry analysts, investors, lenders, rating agencies and others to more effectively evaluate our operating performance and results of operations from period to period and against our peers. We believe Adjusted EBITDAX is a useful performance measure because it allows us to effectively evaluate our operating performance and results of operations from period to period and against our peers, without regard to our financing methods, corporate form or capital structure.

We exclude the items listed above from net income (loss) in arriving at Adjusted EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDAX should not be considered as an alternative to, or more meaningful than, net income (loss) determined in accordance with GAAP. Certain items excluded from Adjusted EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax burden, as well as the historic costs of depreciable assets, none of which are reflected in Adjusted EBITDAX. Our presentation of Adjusted EBITDAX should not be construed as an inference that our results will be unaffected by unusual or non-recurring items. Other companies, including other companies in our industry, may not use Adjusted EBITDAX or may calculate this measure differently than as presented in this prospectus, limiting its usefulness as a comparative measure.

The table below presents a reconciliation of Adjusted EBITDAX to net income, our most directly comparable GAAP financial measure for the periods indicated.

	Six Months Ended June 30,		Year Ended December 31,		
	2024	2023	2023	2022	2021
	(in thousands)				
Net income (loss) attributable to BKV Corporation	$ (98,282)	$ 60,814	$ 116,918	$ 410,142	$(134,463)
Unrealized derivative (gains) losses	79,100	(46,245)	(148,564)	(58,815)	115,161
Forward month gas derivative settlement[1]	83	(2,938)	(9,807)	(8,826)	15,406
Depreciation, depletion, amortization and accretion	111,650	79,026	224,427	130,038	98,833
Exploration and impairment expense	—	—	—	—	34
Change in contingent consideration liabilities	(6,070)	(22,910)	(38,375)	(6,632)	194,968
Interest expense	31,246	34,377	69,942	26,322	—
Interest expense, related party	3,852	3,083	7,078	10,846	2,134
Loss on debt extinguishment	13,877	—	—	—	—
Income tax expense (benefit)	(41,373)	17,885	28,225	62,652	(40,526)
Equity-based compensation expense	2,145	10,295	25,756	31,947	30,387
Bargain purchase gain	—	—	—	(170,853)	—
Gain on sales of non-operated interest in proved reserves	(5,451)	—			
(Earnings) losses from equity affiliate	22,960	14,275	(16,865)	(8,493)	(910)
Total settlements paid (received) for early-terminated derivative contracts during the period[2]	(13,250)	(39,124)	(46,701)	158,448	—
Settlements (paid) received for early-terminated derivative contracts related to the period presented[3]	8,350	8,507	39,124	(1,272)	—
Adjusted EBITDAX	$108,837	$117,045	$ 251,158	$ 575,504	$ 281,024

(1) Natural gas derivative contracts settle and are realized in the month prior to the production covered by the contract. This adjustment removes the timing difference between the settlement date and the underlying production month that is hedged.

(2) Reflects total cash settlements paid (received) during the period upon termination of certain natural gas commodity derivative swap and collar contracts prior to their contractual settlement dates.

(3) When calculating Adjusted EBITDAX for purposes of evaluating our operating performance and results of operations, cash settlements (paid) received for early-terminated derivative contracts are "related to" the period that includes the underlying production month that was hedged. This adjustment removes the timing difference between the early termination date and the underlying production month that is hedged. The table below shows the portion of total cash settlements (paid) received for early-terminated derivative contracts related to the respective periods presented.

	Six Months Ended June 30,		Year Ended December 31,		
	2024	2023	2023	2022	2021
Total cash settlements paid (received) for early-terminated derivative contracts during the period	$(13,250)	$(39,124)	$(46,701)	$158,448	$ —
Cash settlements (paid) received for early-terminated derivative contracts related to the period presented	8,350	$ 8,507	39,124	(1,272)	—
Cash settlements paid (received) for early-terminated derivative contracts related to future periods	$ (4,900)	$(30,617)	$ (7,577)	$157,176	$ —

Adjusted Free Cash Flow

We define Adjusted Free Cash Flow as net cash provided by (used in) operating activities, excluding cash paid for contingent consideration and changes in operating assets and liabilities, less total cash paid for capital expenditures (excluding leasehold costs and acquisitions).

Adjusted Free Cash Flow is not a measure of net cash flow provided by or used in operating activities as determined by GAAP. Adjusted Free Cash Flow is a supplemental non-GAAP financial measure that is used by our management and other external users of our financial statements, such as industry analysts, investors, lenders, rating agencies and others to assess our ability to internally fund our capital program, service or incur additional debt and to pay dividends. We believe Adjusted Free Cash Flow is a useful liquidity measure because it allows us and others to compare cash flow provided by operating activities across periods and to assess our ability to internally fund our capital program (including acquisitions), to reduce leverage, fund acquisitions and pay dividends to our stockholders. Adjusted Free Cash Flow should not be considered as an alternative to, or more meaningful than, net income (loss) or net cash provided by (used in) operating activities determined in accordance with GAAP. Other companies, including other companies in our industry, may not use Adjusted Free Cash Flow or may calculate this measure differently than as presented in this prospectus, limiting its usefulness as a comparative measure.

The table below presents our reconciliation of Adjusted Free Cash Flow to net cash provided by operating activities, our most directly comparable GAAP financial measure for the periods indicated.

	Six Months Ended June 30,		Year Ended December 31,		
	2024	2023	2023	2022	2021
	(in thousands)				
Net cash provided by operating activities	$ 9,782	$ 80,924	$ 123,076	$ 349,194	$ 358,133
Cash paid for contingent consideration[1]	20,000	65,000	65,000	45,300	—
Changes in operating assets and liabilities	68,395	(32,008)	18,437	22,816	(126,862)
Cash paid for capital expenditures	(31,122)	(125,305)	(187,381)	(248,097)	(66,181)
Adjusted Free Cash Flow[2]	$ 67,055	$ (11,389)	$ 19,132	$ 169,213	$ 165,090

(1) Cash paid for contingent consideration is included as a deduction to arrive at net cash provided by (used in) operating activities and therefore, is added back for the purpose of computing Adjusted Free Cash Flow.

(2) The early termination of derivative contracts increased Adjusted Free Cash Flow by $13.3 million, $39.1 million, and $46.7 million during the six months ended June 30, 2024 and 2023, and for the year ended December 31, 2023, respectively, and decreased Adjusted Free Cash Flow by $158.4 million during the year ended December 31, 2022. In addition, Adjusted Free Cash Flow increased by $23.5 million for the six months ended June 30, 2024 due to the net premium received of $23.5 million from the sale of a call option.

Summary Reserves, Production and Operating Data

Ryder Scott, our independent petroleum engineers, prepared estimates of our natural gas, NGL and oil reserves as of December 31, 2023, 2022 and 2021. These reserves estimates were prepared in accordance with the rules and regulations of the SEC regarding oil and natural gas reserves reporting using an average price equal to the unweighted arithmetic average of hydrocarbon prices on the first day of each month within the 12-month period as adjusted for location and quality differentials, unless prices are defined by contractual arrangements, excluding escalations based on future conditions (“SEC Pricing”) (except for the table that provides our estimated reserves as of December 31, 2023 at “NYMEX strip pricing” using pricing based on NYMEX future prices as of market close on December 31, 2023). For more information about our reserves volumes and values, see “*Business — Preparation of Reserves Estimates and Internal Controls*” and Ryder Scott’s summary reserves reports, which are filed as exhibits to the registration statement of which this prospectus forms a part.

The following table provides our estimated proved reserves information prepared by Ryder Scott as of December 31, 2023, 2022 and 2021 and PV-10 Value and the standardized measure of discounted future net cash flows (the “Standardized Measure”) for each period. The decrease in our proved reserves and the PV-10 Value of those reserves as of December 31, 2023, as compared to December 31, 2022, is primarily due to lower commodity pricing. The increase in our proved reserves and the PV-10 Value of those reserves as of December 31, 2022, as compared to December 31, 2021, was primarily due to the Exxon Barnett Acquisition that we consummated on June 30, 2022. There are numerous uncertainties inherent in estimating quantities of natural gas, NGL and oil reserves and their values, including many factors beyond our control. See “*Risk Factors — Risks Related to Our Upstream Business and Industry — Our estimated natural gas, NGL and oil reserves quantities and future production rates are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in the reserves estimates or the underlying assumptions will materially affect the quantities and present value of our reserves*.”

Estimated Reserves at SEC Pricing[1]

	December 31,		
	2023	2022	2021
Estimated proved developed reserves:			
Natural gas (MMcf)	2,443,072	3,798,019	2,494,925
Producing	2,290,025	3,468,896	2,346,712
Non-producing	153,047	329,123	148,213
Natural gas liquids (MBbls)	156,399	170,840	151,433
Producing	129,260	157,585	142,961
Non-producing	27,139	13,255	8,472
Oil (MBbls)	992	1,111	867
Producing	802	1,111	867
Non-producing	190	—	—
Total estimated proved developed reserves (MMcfe)	3,387,418	4,829,733	3,408,725
Producing	3,070,397	4,421,072	3,209,680
Non-producing	317,021	408,653	199,045
Standardized Measure (millions)	$ 986	$ 5,809	$ 2,119
PV-10 (millions)[2][3]	$ 1,151	$ 7,389	$ 2,672

	December 31, 2023	December 31, 2022	December 31, 2021
Estimated proved undeveloped reserves:			
Natural gas (MMcf)	539,423	1,057,657	950,358
Natural gas liquids (MBbls)	27,766	40,660	13,722
Oil (MBbls)	59	758	58
Total estimated proved undeveloped reserves (MMcfe)(4)(5)	706,373	1,306,157	1,033,038
Standardized Measure (millions)	$ 48	$ 1,185	$ 295
PV-10 (millions)(2)(6)	$ 81	$ 1,566	$ 403
Estimated total proved reserves:			
Natural gas (MMcf)	2,982,495	4,855,676	3,445,283
Natural gas liquids (MBbls)	184,165	211,500	165,155
Oil (MBbls)	1,051	1,869	925
Total estimated proved reserves (MMcfe)	4,093,791	6,135,890	4,441,763
Standardized Measure (millions)	$ 1,034	$ 6,994	$ 2,414
PV-10 (millions)(2)(7)	$ 1,232	$ 8,955	$ 3,075

(1) Prices for natural gas, oil and NGLs, respectively, used in preparing our estimated proved reserves and the associated PV-10 Value based on SEC Pricing (i) at December 31, 2023 were $2.637 per MMBtu (Henry Hub), $78.22 per Bbl (WTI Cushing) and NGL pricing equal to 29.5% of WTI Cushing, (ii) at December 31, 2022 were $6.358 per MMBtu (Henry Hub), $93.67 per Bbl (WTI Cushing) and NGL pricing equal to 36.7% of WTI Cushing and (iii) at December 31, 2021 were $3.598 per MMBtu (Henry Hub), $66.56 per Bbl (WTI Cushing) and NGL pricing equal to 39.5% of WTI Cushing.

(2) PV-10 refers to the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect at the determination date, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%. PV-10 is not a financial measure calculated in accordance with GAAP because it does not include the effects of income taxes on future net revenues. PV-10 is derived from the Standardized Measure, which is the most directly comparable GAAP financial measure. Neither PV-10 nor Standardized Measure represent an estimate of the fair market value of our oil and natural gas properties. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and gas properties. It is not intended to represent the current market value of our estimated reserves. PV-10 should not be considered in isolation or as a substitute for the Standardized Measure reported in accordance with GAAP, but rather should be considered in addition to the Standardized Measure.

(3) The following table provides a reconciliation of the Standardized Measure to PV-10 with respect to estimated proved developed reserves as of December 31, 2023, 2022 and 2021:

	December 31, 2023	December 31, 2022	December 31, 2021
PV-10 (millions)	$1,151	$ 7,389	$2,672
Present value of future income taxes discounted at 10%	(165)	(1,580)	(553)
Standardized Measure	$ 986	$ 5,809	$2,119

(4) Proved undeveloped reserves as of December 31, 2023 are part of a development plan that has been adopted by management indicating that such locations are scheduled to be drilled within five years. Proved undeveloped reserves as of December 31, 2022 and 2021 were part of a development plan adopted by management indicating that such locations were scheduled to be drilled within five years of initial booking.

(5) Sustained lower prices for oil and natural gas may cause us to forecast less capital to be available for development of our proved undeveloped reserves, which may cause us to decrease the amount of our proved undeveloped reserves we expect to develop within the allowed time frame. In addition, lower oil and natural gas prices may cause our proved undeveloped reserves to become uneconomic to develop, which would cause us to remove them from their respective reserves category.

(6) The following table provides a reconciliation of the Standardized Measure to PV-10 with respect to estimated proved undeveloped reserves as of December 31, 2023, 2022 and 2021:

	December 31,		
	2023	2022	2021
PV-10 (millions)	$ 81	$1,566	$ 403
Present value of future income taxes discounted at 10%	(33)	(381)	(108)
Standardized Measure	$ 48	$1,185	$ 295

(7) The following table provides a reconciliation of the Standardized Measure to PV-10 with respect to estimated proved reserves as of December 31, 2023, 2022 and 2021:

	December 31,		
	2023	2022	2021
PV-10 (millions)	$1,232	$ 8,955	$3,074
Present value of future income taxes discounted at 10%	(198)	(1,961)	(661)
Standardized Measure	$1,034	$ 6,994	$2,413

During the years ended December 31, 2023, 2022 and 2021, we incurred costs of approximately $37.7 million, $54.0 million and $7.2 million, respectively, to convert 31.9 Bcfe, 74.0 Bcfe and 19.4 Bcfe, respectively, of proved undeveloped reserves to proved developed reserves. Estimated future development costs relating to the development of our proved undeveloped reserves at December 31, 2023, 2022 and 2021 are approximately $356.2 million, $1,089.6 million and $578.3 million, respectively, over the next five years, substantially all of which we expect to finance through cash flow from operations and/or borrowings under our RBL Credit Agreement. Our development programs through the year ended December 31, 2023 focused on refracturing under-stimulated wells and designing and drilling new wells in both our Barnett and NEPA assets. Our proved undeveloped reserves, as of December 31, 2023, are scheduled to be developed within five years of their initial disclosure. See "*Risk Factors — Risks Related to Our Upstream Business and Industry — The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate.*"

Natural gas prices decreased significantly during 2023 and are projected to remain lower than the near-record high prices experienced in 2022. Due to our desire to be a prudent operator and exercise capital discipline in this pricing environment, subsequent to finalizing our reserve reports as of December 31, 2023, we decreased our capital expenditures budget for development of natural gas properties for 2024 to approximately $13.0 million from our original budget of approximately $73.0 million, which was the amount applied in connection with the preparation of the estimates of our reserves as of December 31, 2023. We estimate that this reduction in our 2024 capital expenditures would result in a decrease in our proved reserves, standardized measure value of proved reserves, and the PV-10 value of proved reserves as of December 31, 2023 by approximately 3.3%, 1.6%, and 2.0%, respectively. If the current lower natural gas commodity pricing environment extends beyond 2024, we will continue to maintain capital discipline and reflect corresponding capital expenditure changes in our estimated reserves. These changes would mainly impact proved undeveloped reserves and proved developed non-producing reserves, which collectively represent approximately 25% of our total estimated proved reserves as of December 31, 2023.

2023 Activity

During the year ended December 31, 2023, the Company's proved reserves decreased by 2,042.1 Bcfe. The decrease in proved reserves was primarily attributable to decreased commodity pricing and changes in the Company's drilling activity, which resulted in total downward revisions of 1,986.3 Bcfe. As discussed below, these decreases were partially offset by extensions and discoveries and improved recoveries experienced by the Company in 2023, which resulted in net increases to proved reserves of 227.8 Bcfe and 30.2 Bcfe, respectively. The Company produced 313.8 Bcfe during the year ended December 31, 2023.

Revisions of previous estimates primarily consisted of downward revisions to proved developed reserves and proved undeveloped reserves of 1,191.9 Bcfe and 273.1 Bcfe, respectively, as a result of lower average pricing during 2023 for natural gas, NGLs, and oil. Additional downward revisions were made to proved undeveloped reserves of 521.3 Bcfe due to the Company's lower capital spend and the resulting reduction in drilling activity during 2023. Changes to the Company's drilling schedule moved the development of 112.0 gross (104.6 net) locations in NEPA and the Barnett beyond the SEC requirement of developing PUDs five years from initial booking. These 112.0 gross (104.6 net) locations remain in the Company's inventory of unproved locations to be developed outside of the next five years. The drilling schedule changes reflect the Company's ongoing commitment to optimize the long-term plan to best develop its assets, maximize cash flow, and produce economic returns.

Extensions and discoveries primarily consisted of 226.5 Bcfe of proved undeveloped reserves, of which 197.8 Bcfe was attributable to 22.0 gross (21.2 net) locations recognized as a result of the Company's optimized drilling program, which reduced costs and extended lateral lengths. In addition, 28.7 Bcfe was attributable to extensions related to 3.0 gross (1.1 net) locations in NEPA. Our unitization and combination of acreage with Repsol resulted in the three additional locations.

Improved recoveries consisted of 30.2 Bcfe of proved developed reserves recognized as a result of the application of improved recovery techniques to producing wells during the year ended December 31, 2023.

Conversions of proved undeveloped reserves to proved developed reserves consisted of 31.9 Bcfe related to the completion of 22.0 gross (8.1 net) wells on proved undeveloped locations during the year ended December 31, 2023.

2022 Activity

During the year ended December 31, 2022, the Company's proved reserves increased by 1,694.1 Bcfe. The increase in proved reserves was primarily due to the acquisition of the 2022 Barnett Assets. Other factors that contributed to the increase in proved reserves during 2022 included increasing commodity pricing, which improved economics, improved recoveries due to the application of restimulation technology to producing wells and the addition of NGL rich locations to the drilling schedule. The Company produced 279.5 Bcfe during the year ended December 31, 2022.

Revisions of previous estimates consisted of upward revisions to proved developed reserves of 182.9 Bcfe as a result of higher average pricing during 2022 for natural gas, NGLs and oil. An additional upward revision of 52.0 Bcfe was made to proved developed reserves for performance adjustments. Upward revisions were offset by downward revisions to proved undeveloped reserves of 246.0 Bcfe relating to 76.0 gross (53.1 net) locations in NEPA and the Barnett that were removed from the drilling schedule in exchange for locations with more favorable economics, as discussed in the following explanation of extensions and discoveries in 2022. Additional downward revisions of 67.3 Bcfe and 42.9 Bcfe were made to proved undeveloped reserves related to performance and increased development costs, respectively.

Extensions and discoveries primarily consisted of the addition of 389.5 Bcfe of proved undeveloped reserves from 71.0 gross (66.4 net) locations recognized as a result of our revised evaluation of properties acquired through our Devon Barnett Acquisition. The added locations are more rich in NGLs than the previously recognized locations that were removed from the 2021 drilling schedule, as discussed in the preceding explanation of revisions of previous estimates in 2022. Additional extensions consisted of proved undeveloped reserves of 85.8 Bcfe related to 27.0 gross (12.8 net) locations in NEPA and the Barnett that were recognized from acreage acquired in 2021 and as a result of the revised 2022 drilling plan. Extensions related to proved developed reserves of 74.1 Bcfe consisted of 23.0 gross (13.0 net) newly drilled wells on locations previously classified as unproved.

Purchases of minerals in place consisted of 1,237.1 Bcfe and 227.9 Bcfe of proved developed and proved undeveloped reserves, respectively, from the Exxon Barnett Acquisition. The acquired reserves consisted of operated working interests in 2,289.0 gross (1,696.4 net) wells and 53.0 gross (48.7 net) undeveloped locations.

Improved recoveries consisted of 80.5 Bcfe of proved developed reserves recognized as a result of the application of improved recovery techniques to producing wells during the year ended December 31, 2022.

Conversions of proved undeveloped reserves to proved developed reserves consisted of 73.9 Bcfe related to the completion of 19.0 gross (5.5 net) wells on proved undeveloped locations during the year ended December 31, 2022.

2021 Activity

During the year ended December 31, 2021, the Company's proved reserves increased by 1,808.5 Bcfe. The increase in proved reserves was primarily due to increasing commodity pricing improving economics, and additions to the drilling schedule for both proved developed and undeveloped reserves. The Company produced 245.8 Bcfe during the year ended December 31, 2021.

Revisions of previous estimates primarily consisted of upward revisions to proved developed reserves and proved undeveloped reserves of 715.9 Bcfe and 245.6 Bcfe, respectively, as a result of higher average pricing during 2021 for natural gas, NGLs and oil. The remaining upward adjustment of 139.8 Bcfe relates to upward performance adjustments of 219.2 Bcfe to proved developed reserves offset by a downward revision of 79.4 Bcfe to proved developed reserves due to increased production costs.

Extensions and discoveries increased as a result of the completion of our evaluation of properties acquired through our Devon Barnett Acquisition, 550.1 Bcfe of proved undeveloped reserves was recognized for 123.0 gross (94.8 net) locations added to the Company's revised drilling schedule during 2021. Additional extensions consisted of proved undeveloped reserves of 162.5 Bcfe related to 13.0 gross (9.6 net) locations in NEPA recognized from acquired acreage and the revised 2021 drilling plan. Extensions related to proved developed reserves of 15.4 Bcfe consisted of 10.0 gross (3.0 net) newly drilled wells.

Purchases of minerals in place consisted of 17.7 Bcfe of proved developed reserves from the acquisition of additional working interests in 601.0 gross (14.6 net) wells and 1.8 Bcfe of proved undeveloped reserves from the acquisition of additional working interests in 18.0 gross (1.0 net) locations, each of which were in addition to the Company's previously held working interests in wells or working interests in locations in the Barnett.

Improved recoveries consisted of 205.4 Bcfe of proved developed reserves recognized as a result of the application of improved recovery techniques to producing wells during the year ended December 31, 2021.

Conversions of proved undeveloped reserves to proved developed reserves consisted of 19.4 Bcfe related to the completion of 4.0 gross (3.9 net) wells on proved undeveloped locations during the year ended December 31, 2021.

Estimated Reserves at NYMEX Strip Pricing

The following table provides our total estimated proved reserves information prepared by Ryder Scott as of December 31, 2023, using NYMEX strip prices as of market close on December 31, 2023 and PV-10 Value and the Standardized Measure for such period. We have included this information in order to provide an additional method of presentation of the fair value of our assets and the cash flows that we expect to generate from those assets based on the market's forward-looking pricing expectations as of December 31, 2023. The historical 12-month pricing average in our December 31, 2023 disclosures above does not reflect the prevailing natural gas and oil futures. We believe that the use of forward prices provides investors with additional useful information about our reserves, as the forward prices are based on the market's forward-looking expectations of natural gas and oil prices as of a certain date, although we caution investors that this information should be viewed as a helpful alternative, not a substitute, for the data presented based on SEC Pricing. In addition, we believe that NYMEX strip pricing provides relevant and useful information because it is widely used by investors in our industry as a basis for comparing the relative size and value of our reserves to our peers. Our estimated reserves based on NYMEX futures were otherwise prepared on the same basis as our SEC reserves for the comparable period. Actual future prices may vary significantly from the NYMEX strip prices on December 31, 2023. Actual revenue and value generated may be more or less than the amounts disclosed. There are numerous uncertainties inherent in estimating quantities of natural gas, NGL and oil reserves and their values, including many factors beyond our control. See "*Risk Factors — Risks Related to Our Upstream Business and Industry — Our estimated natural gas, NGL and oil reserves quantities and future production rates are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in the reserves estimates or the underlying assumptions will materially affect the quantities and present value of our reserves*."

	December 31, 2023
Estimated proved developed reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	2,984,949
Producing	2,791,791
Non-producing	193,158
Natural gas liquids (MBbls)	164,204
Producing	134,689
Non-producing	29,515
Oil (MBbls)	1,046
Producing	808
Non-producing	238
Total estimated proved developed reserves (MMcfe)	3,976,436
Producing	3,604,773
Non-producing	371,663
Standardized Measure (millions)	$ 1,651
PV-10 (millions)(1)	$ 2,015
Estimated proved undeveloped reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	790,838
Natural gas liquids (MBbls)	30,500
Oil (MBbls)	59
Total estimated proved undeveloped reserves (MMcfe)(2)(3)	974,192
Standardized Measure (millions)	$ 244
PV-10 (millions)(4)	$ 335
Estimated total proved reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	3,775,787
Natural gas liquids (MBbls)	194,704
Oil (MBbls)	1,105
Total estimated proved reserves (MMcfe)	4,950,628
Standardized Measure (millions)	$ 1,895
PV-10 (millions)(5)	$ 2,350

(1) The following table provides a reconciliation of the Standardized Measure to PV-10 (applying NYMEX Strip Pricing) with respect to estimated proved developed reserves as of December 31, 2023:

	December 31, 2023
PV-10 (millions)	$ 2,015
Present value of future income taxes discounted at 10%	(364)
Standardized Measure	$ 1,651

(2) Proved undeveloped reserves as of December 31, 2023 are part of a development plan that has been adopted by management indicating that such locations are scheduled to be drilled within five years.

(3) Sustained lower prices for oil and natural gas may cause us to forecast less capital to be available for development of our proved undeveloped reserves, which may cause us to decrease the amount of our proved undeveloped reserves we expect to develop within the allowed time frame. In addition, lower oil and natural gas prices may cause our proved undeveloped reserves to become uneconomic to develop, which would cause us to remove them from their respective reserves category.

(4) The following table provides a reconciliation of the Standardized Measure to PV-10 (applying NYMEX Strip Pricing) with respect to estimated proved undeveloped reserves as of December 31, 2023:

	December 31, 2023
PV-10 (millions)	$ 335
Present value of future income taxes discounted at 10%	(91)
Standardized Measure	$ 244

(5) The following table provides a reconciliation of the Standardized Measure to PV-10 (applying NYMEX Strip Pricing) with respect to estimated proved reserves as of December 31, 2023:

	December 31, 2023
PV-10 (millions)	$ 2,350
Present value of future income taxes discounted at 10%	(455)
Standardized Measure	$ 1,895

RISK FACTORS

Investing in our common stock involves risks. The information in this prospectus should be considered carefully, including the matters addressed under "Cautionary Statement Regarding Forward-Looking Statements" and the following risks, before making an investment decision. The risks and uncertainties described below are not the only ones we face. Additional risks not presently known to us or that we currently deem immaterial may also materially affect our business. The occurrence of any of the following risks or additional risks and uncertainties that are currently immaterial or unknown could materially and adversely affect our business, financial condition, liquidity, results of operations, cash flows or prospects. The trading price of our common stock could decline due to any of these risks, and you may lose all or part of your investment.

Risks Related to Our Upstream Business and Industry

The volatility of natural gas and NGL prices due to factors beyond our control may materially and adversely affect our business, financial condition or results of operations and our ability to make capital expenditures and meet our debt service obligations.

Our revenues, operating results, available cash and the carrying value of our natural gas properties, as well as our ability to make capital expenditures (including the $36.0 million estimated total project cost of the Barnett Zero Project, the $9.0 million we expect to contribute to BKV-BPP Cotton Cove to fund our portion of the estimated total cost of the Cotton Cove Project and the $57.0 million (inclusive of funding to date of $26.0 million) we expect to invest in BKVerde before the end of 2025 in connection with our efforts to develop potential CCUS projects) and meet our debt service obligations and other financial commitments, depend significantly upon the prevailing market prices for natural gas and NGLs. According to the U.S. Energy Information Administration (the "EIA"), the historical high and low Henry Hub natural gas spot prices per MMBtu for the following periods were as follows: in 2021, high of $23.86 and low of $2.43; in 2022, high of $9.85 and low of $3.46; in 2023, high of $3.78 and low of $1.74; and for the six months ended June 30, 2024, high of $13.20 and low of $1.25.

Prices for natural gas and NGLs are subject to wide fluctuations in response to relatively minor changes in supply and demand, market uncertainty and a variety of additional factors beyond our control. These factors include, but are not limited to:

- worldwide and regional economic conditions impacting the global supply of, and demand for, natural gas and NGLs, including inflation;
- the price, amount, timing and quantity of foreign imports of natural gas and NGLs;
- political conditions in or affecting other producing countries, including the armed conflicts between Russia and Ukraine and Israel and Hamas, and associated economic sanctions on Russia and conditions in China, the Middle East, Africa and South America;
- the level of global drilling, exploration and production;
- the level of global inventories;
- prevailing market prices on local price indexes in the areas in which we operate and expectations about future commodity prices;
- the impact on worldwide economic activity of an epidemic, outbreak or other public health events, such as the COVID-19 (including any variants thereof, "COVID-19") pandemic or threat of such epidemic or outbreak, or any government response to such occurrence or threat;
- increased associated natural gas and NGL production resulting from higher oil prices and the related increase in oil production;
- the proximity of our natural gas and NGL production to, and capacity and cost of, natural gas and NGL pipelines and other transportation and storage facilities, and other factors that result in differentials to benchmark prices;
- local and global supply and demand fundamentals and transportation availability;
- United States storage levels of natural gas and NGLs;

- weather conditions and other natural disasters;
- domestic and foreign governmental regulations, including environmental initiatives and taxation;
- overall domestic and global economic conditions;
- the value of the dollar relative to the currencies of other countries;
- stockholder activism or activities by non-governmental organizations to restrict the exploration, development and production of natural gas, NGLs and oil to minimize emissions of carbon dioxide, a GHG;
- the actions of OPEC and other oil producing countries, including Russia;
- speculative trading in natural gas and NGL derivative contracts;
- technological advances affecting energy consumption and energy supply;
- the price, availability and acceptance of alternative energy sources; and
- the impact of energy conservation efforts.

These factors and the volatility of the energy markets make it extremely difficult to predict future natural gas price movements accurately. Changes in natural gas and NGL prices have a significant impact on the amount of natural gas and NGLs that we can produce economically, the value of our reserves, our cash flows and our ability to satisfy obligations under our firm transportation and storage agreements. Historically, natural gas and NGL prices and markets have been volatile, and those prices and markets are likely to continue to be volatile in the future. For example, during the period from January 1, 2021 through June 30, 2024, the Henry Hub natural gas spot price reached a high of $23.86 per MMBtu on February 17, 2021 and a low of $1.25 per MMBtu on March 13, 2024. Henry Hub natural gas spot prices trended higher after the Russia-Ukraine conflict first commenced, rising from $4.78 per MMBtu on February 24, 2022 to a high of $9.85 per MMBtu on August 22, 2022, according to the EIA; however, such prices subsequently dropped to $3.52 per MMBtu on December 31, 2022, as a result of a warmer-than-normal winter, and then to a recent low of $1.25 per MMBtu on March 13, 2024 due to a combination of higher production and higher storage inventories given a mild winter. Prices continued to hover on average between $1.50 to $2.50 in the first half of 2024 with overall lower natural gas consumption and higher storage inventory levels during the 2023-2024 winter.

A substantial percentage of our natural gas and NGL production is gathered, processed and transported by a single third party and all of our natural gas production is marketed by a single third party.

Approximately 99% of our natural gas and NGL production for the assets we acquired in the Devon Barnett Acquisition, which comprised approximately 61% for the six months ended June 30, 2024 and for the year ended December 31, 2023, and 69% and 77%, for the years ended December 31, 2022 and 2021, respectively, of our total natural gas and NGL production was gathered, processed and transported by EnLink using its gas gathering systems, gas transportation system and gas processing facilities. Any termination or sustained disruption in the gathering, processing and transportation of our natural gas and NGL production by EnLink on its systems and in its facilities would materially and adversely affect our financial condition and results of operations.

We utilize an unaffiliated third party to market all of our natural gas production to various purchasers, which consist of credit-worthy counterparties, including utilities, LNG producers, industrial consumers, major corporations and super majors, in our industry. We rely on the credit worthiness of such third-party marketer, who collects directly from the purchasers and remits to us the total of all amounts collected on our behalf less their fee for making such sales. Our business, financial condition and results of operations would be materially adversely affected if such third party fails to remit to us amounts collected by it on our behalf for such sales or if, in the future, it becomes necessary or advisable for us to replace our third-party marketer and we experience disruption in the marketing and sale of our natural gas production for so long as we are unable to find a replacement marketer.

Our estimated natural gas, NGL and oil reserves quantities and future production rates are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in the reserves estimates or the underlying assumptions will materially affect the quantities and present value of our reserves.

Numerous uncertainties are inherent in estimating quantities of natural gas, NGL and oil reserves. The process of estimating natural gas, NGL and oil reserves is complex, requiring significant decisions and assumptions in the evaluation of available geological, engineering and economic data for each reservoir, including assumptions regarding future natural gas, NGL and oil prices, subsurface characterization, production levels and operating and development costs. For example, our estimates of our reserves at SEC Pricing are based on the unweighted first-day-of-the-month arithmetic average commodity prices over the prior 12 months in accordance with SEC guidelines. Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of those estimates. Sustained lower natural gas, NGL and oil prices will cause the 12-month unweighted arithmetic average of the first-of-the-day price for each of the 12 months preceding to decrease over time as the lower natural gas, NGL and oil prices are reflected in the average price, which may result in the estimated quantities and present values of our reserves being reduced. To the extent that natural gas, NGL and oil prices become depressed or decline materially from current levels, such conditions could render uneconomic a portion of our proved natural gas, NGL and oil reserves, and we may be required to write down our proved reserves.

Furthermore, SEC rules require that, subject to limited exceptions, PUD reserves may only be recorded if they relate to wells scheduled to be drilled within five years after the date of booking. This rule may limit our potential to record additional PUD reserves as we pursue our drilling program. To the extent that natural gas, NGL and oil prices become depressed or decline materially from current levels, such condition could render uneconomic a number of our identified drilling locations, and we may be required to write down our PUD reserves if we do not drill those wells within the required five-year time frame or choose not to develop those wells at all.

As a result, estimated quantities of natural gas, NGL and oil reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. Over time, we may make material changes to our reserves estimates. Any significant variance in our assumptions and actual results could greatly affect our estimates of reserves, the economically recoverable quantities of natural gas, NGL and oil attributable to any particular group of properties, the classifications of reserves based on risk of non-recovery and estimates of future net cash flows.

The present value of future net revenues from our proved natural gas, NGL and oil reserves, or PV-10, will not necessarily be the same as the current market value of our estimated proved natural gas, NGL and oil reserves.

You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated natural gas, NGL and oil reserves. We currently base the estimated discounted future net revenues from our proved reserves on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the preceding 12 months. Actual future net revenues from our natural gas, NGL and oil reserves will be affected by factors such as:

- actual prices we receive for natural gas, NGL and oil;
- actual cost of development and production expenditures;
- the amount and timing of actual production;
- transportation and processing; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of our natural gas, NGL and oil properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net revenues may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas, NGL and oil industry in general. Actual future prices and costs may differ materially from those used in the present value estimate.

The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate.

Recovery of PUD reserves requires significant capital expenditures and successful drilling operations. As of December 31, 2023, approximately 706.4 Bcfe, or 17.3%, of our total estimated proved reserves were undeveloped or behind pipe. The reserves data included in our reserves report assumes that substantial capital expenditures will be made to develop non-producing reserves. We cannot be sure that the estimated costs attributable to our natural gas, NGL and oil reserves are accurate. We may need to raise additional capital to develop our estimated PUD reserves over the next five years and we cannot be certain that additional financing will be available to us on acceptable terms or at all. Additionally, sustained or further declines in commodity prices may require us to revise the future net revenues of our estimated PUD reserves and may result in some projects becoming uneconomical. Further, our drilling efforts may be delayed or unsuccessful and actual reserves may prove to be less than current reserves estimates, which could have a material adverse effect on our financial condition, future cash flows and results of operations.

As part of our exploration and development operations, we have expanded, and expect to further expand, the application of horizontal drilling and multi-stage hydraulic fracture stimulation techniques. The utilization of these techniques requires substantially greater capital expenditures, as compared to the completion cost of a vertical well and therefore may result in fewer wells being completed in any given year. The incremental required capital expenditures are the result of greater measured depths and additional hydraulic fracture stages in horizontal wellbores.

Unless we replace our reserves with new reserves and develop those reserves, our reserves and production will decline, which would adversely affect our future cash flows and results of operations.

In general, the volume of production from natural gas, NGL and oil properties declines as reserves are depleted, with the rate of decline depending on each reservoir's characteristics. Except to the extent that we conduct successful exploration, exploitation and development activities or acquire properties containing proved reserves, or both, our proved reserves will decline as reserves are produced. Our future natural gas and NGL production is, therefore, highly dependent on our level of success in finding or acquiring additional reserves as well as the pace of drilling and completion of new wells. Additionally, the business of exploring for, exploiting, developing or acquiring reserves is capital intensive. Recovery of our reserves, particularly undeveloped reserves, will require significant additional capital expenditures and successful drilling operations. To the extent cash flow from operations is reduced and external sources of capital become limited or unavailable, our ability to make the necessary capital investment to maintain or expand our asset base of natural gas and NGL reserves would be impaired.

If natural gas and NGL prices become depressed for extended periods of time or decline materially from current levels, we may be required to record write-downs of the carrying value of our proved natural gas and NGL properties.

We follow the successful efforts method of accounting for natural gas producing activities. Impairment is indicated when a triggering event occurs and the sum of the estimated undiscounted future net cash flows of an evaluated asset is less than the asset's carrying value. If undiscounted future cash flows are insufficient to recover the net capitalized costs related to proved properties, then we recognize an impairment charge in our results of operations equal to the difference between the net capitalized costs related to proved properties and their estimated fair values based on the present value of the related future net cash flows. Triggering events could include, but are not limited to, an impairment of natural gas and NGL reserves caused by mechanical problems, faster-than-expected decline of reserves, lease-ownership issues, declines in commodity prices and changes in the utilization of midstream gathering and processing assets. If impairment is indicated, fair value is calculated using a discounted-cash flow approach and any excess of carrying value is expensed. Undeveloped natural gas and NGL properties are evaluated for impairment on a regular basis, based on the results of the exploratory activity and management's evaluation. If the assessment indicates an impairment, an impairment loss is recognized. Future price decreases could result in reductions in the carrying value of our assets and an equivalent charge to earnings.

We periodically evaluate our unproved natural gas, NGL and oil properties to determine recoverability of our costs and could be required to recognize non-cash charges in the earnings of future periods.

As of June 30, 2024, we carried unproved natural gas, NGL and oil property costs of $10.5 million. GAAP requires periodic evaluation of unproved natural gas, NGL and oil property costs on a project-by-project basis. These evaluations are affected by the results of exploration activities, commodity price outlooks, planned future sales or expirations of all or a portion of these leases and the contracts and permits relevant to such projects. If the quantity of potential reserves determined by such evaluations is not sufficient to fully recover the costs invested in each project, we will recognize non-cash charges in future periods.

Properties that we have acquired or which we may acquire in the future may not produce as projected, and we may be unable to determine reserves potential, identify liabilities associated with such properties or obtain protection from sellers against such liabilities.

Acquiring natural gas and NGL properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential liabilities, including environmental liabilities. Such assessments are inherently inexact and uncertain. For these reasons, the properties we have acquired or will acquire in the future may not produce as projected. Further, the annual decline rates of reserves are estimated decline rates, which could ultimately be materially different than actual annual decline rates. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an “as is” basis. We perform a review of the subject properties, but such a review will not reveal all existing or potential problems. In the course of our due diligence, we may not review every well, pipeline or associated facility. We cannot necessarily observe structural and environmental problems, such as pipe corrosion or groundwater contamination, when a review is performed. We may be unable to obtain contractual indemnities from the seller for liabilities created prior to our purchase of the property. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

Our failure to correctly assess reservoir and infrastructure characteristics of the natural gas and NGL properties that we acquire or have acquired, or to identify material defects or liabilities associated with such properties, or actual decline rates that differ materially from estimated decline rates, could have a material adverse effect on our financial condition, results of operations and cash flows.

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

Market conditions or the unavailability of natural gas and NGL processing, transportation or storage arrangements may hinder our access to natural gas and NGL markets or delay or curtail our production. The availability of a ready market for our natural gas and NGL production depends on a number of factors, including the demand for and supply of natural gas and NGLs, the proximity of our natural gas and NGL production to and capacity of pipelines and storage facilities, gathering systems and other transportation, processing, fractionation, refining and export facilities, competition for such facilities and the inability of such facilities to gather, transport, store or process our natural gas and NGL production due to shutdowns or curtailments arising from mechanical, operational or weather related matters, including hurricanes and other severe weather conditions, or pandemics such as the COVID-19 pandemic or regulatory action related thereto.

Our firm transportation and storage agreements require us to pay demand charges for firm transportation and storage capacities that we do not utilize. If we fail to utilize our firm transportation and storage capacities due to production shortfalls or otherwise, then our margins, results of operations and financial performance could be adversely affected.

We enter into long-term firm transportation agreements, which as of June 30, 2024, provided us with a network of approximately 1,193,000 MMBtu/d of combined firm transportation capacity to East Coast, Gulf Coast, and Southeast markets as it relates to our upstream business units. Additionally, BKV-BPP Power has long-term firm transportation and storage agreements, which, as of June 30, 2024, provided BKV-BPP Power with a combined 200,000 MMBtu/d of firm transportation with Atmos and Energy Transfer and 2,812,500 MMBtu of firm storage with Energy Transfer. We are obligated under these arrangements to pay a demand charge for firm transportation and storage capacity rights on a majority these pipeline and storage systems regardless of the amount of pipeline or storage capacity we utilize, subject to our right to release all or a portion of our firm transportation or storage capacities to other shippers and reduce our exposure to demand charges. As of June 30, 2024, our minimum aggregate required payments per year under firm gathering and transportation agreements are approximately $34.5 million for 2024, $68.2 million for 2025, $66.4 million for 2026, $58.6 million for 2027, $53.2 million for 2028 and $73.2 for 2029 and beyond. See "*Business — Marketing and Differentials*."

If our anticipated production does not exceed the minimum quantities provided in the agreements, and we are unable to purchase natural gas and NGLs from third parties or release our capacity to other shippers, then our margins, results of operations and financial performance could be adversely affected.

Drilling for natural gas wells is a high-risk activity with many uncertainties that could adversely affect our business, financial condition or results of operations.

Drilling natural gas wells, including development wells, involves numerous risks, including the risk that we may not encounter commercially productive natural gas and NGL reserves (including "dry holes"). We must incur significant expenditures to drill and complete wells, the costs of which are often uncertain. It is possible that we will make substantial expenditures on drilling and not discover reserves in commercially viable quantities.

Specifically, we often are uncertain as to the future cost or timing of drilling, completing and operating wells, and our drilling operations and those of our third-party operators may be curtailed, delayed or canceled. The cost of our drilling, completing and well operations may increase and our results of operations and cash flows from such operations may be impacted, as a result of a variety of factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions, such as winter storms, flooding and hurricanes, and changes in weather patterns;
- compliance with, or changes in, environmental laws and regulations relating to air emissions, hydraulic fracturing and disposal of produced water, drilling fluids and other wastes, laws and regulations imposing conditions and restrictions on drilling and completion operations and other laws and regulations, such as tax laws and regulations;
- the availability and timely issuance of required governmental permits and licenses; and
- the availability of, costs associated with, and terms of contractual arrangements for, properties, including mineral licenses and leases, pipelines, facilities and equipment to gather, process, compress, store, transport and market natural gas and NGLs and related commodities.

For instance, in our drilling operations across NEPA and the Barnett from time to time we experience certain issues and the occurrence of risks, including, for example, mechanical and instrument or tool failures, drilling difficulties associated with drilling in swelling clay or shales and unconsolidated formation, particularly in certain parts of our Barnett development acreage, wellbore instability and other geological hazards, loss of well control, loss of drilling fluids, inability to establish fluid circulation, loss of drill pipe, loss of casing integrity, stuck tools and drill pipes, insufficient cementing of casing, among other typical shale drilling challenges.

Our failure to recover our investment in wells, increases in the costs of our drilling operations or those of our third-party operators, and/or curtailments, delays or cancellations of our drilling operations or those of our third-party operators in each case due to any of the above factors or other factors, may materially and adversely affect our business, financial condition and results of operations.

Drilling, completions, workover and hydraulic fracturing operations are operationally complex activities which present certain risks that could adversely affect our business, financial condition or results of operations.

In our drilling operations, from time to time we experience certain issues and encounter risks, including, for example, mechanical and instrument or tool failures; drilling difficulties associated with drilling in swelling clay or shales and unconsolidated formation, particularly in select parts of our Barnett development acreage; wellbore instability and other geological hazards; loss of well control and associated hydrocarbon release and/or natural gas clouds; loss of drilling fluids circulation; surface spills of various drilling or well fluids; subsurface collision with existing wells; proximity of adjacent water wells or aquifers; inability to establish drilling fluid circulation; loss or compromise of drill pipe or casing integrity; surface pumping operations and associated pressure and hydrocarbon hazards; stuck and lost-in-hole tools, drill pipe or casing; large drilling equipment and machinery including electrical hazards; insufficient cementing of casing causing unwanted casing pressure or fluid migration; surface overpressure events from large machinery (horsepower), equipment or well pressure; fines and violations related to relevant laws and regulations; fires and explosions; personnel safety hazards such as working at heights, driving or equipment operation, energy isolation, excavation and trenching and more; structural damage and collapse to large equipment and machinery; major damage or malfunction to key equipment or processes; in certain instances, close proximity of operations to residences and/or communities; among other typical shale basin drilling challenges and risks.

In our hydraulic fracturing, workover and completions activities, from time to time we experience certain issues and encounter risks, including, for example, mechanical and instrument or tool failures; loss of well control and associated hydrocarbon release and/or natural gas clouds; well kick or flowback during completion or fracturing operations; lost or stuck in hole wireline, coiled tubing or workover strings and tools; loss or compromise of workover string, tubing or casing integrity; large completions, wireline, coiled tubing and workover rig equipment and machinery including electrical hazards; insufficient cementing of casing causing unwanted casing pressure or fluid migration while fracturing or thereafter; proximity of adjacent water wells or aquifers and adjacent producing wells; surface spills of various fracturing, freshwater or well fluids or chemicals; surface pumping and flowback operations and associated pressure and hydrocarbon hazards; surface overpressure events from large machinery (horsepower), equipment or well pressure; fines and violations related to relevant laws and regulations; fires and explosions; personnel safety hazards such as working at heights, driving or equipment operation, energy isolation, excavation and trenching and more; structural damage and collapse to large equipment and machinery; major damage or malfunction to key equipment or processes; in certain instances, close proximity of operations to residences and/or communities; among other typical fracturing, workover and completion challenges and risks.

We may incur losses as a result of title defects in the properties in which we invest.

It is our practice in acquiring oil and natural gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest at the time of acquisition. Rather, we rely upon the judgment of lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease or other interest in a specific mineral interest. The existence of a material title deficiency can render a lease or other interest worthless and can adversely affect our results of operations and financial condition. The failure of title on a lease, in a unit or any other mineral interest may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

Our identified drilling locations are scheduled to be drilled over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill such locations.

Our management team has identified drilling locations as an estimation of our future development activities on our existing acreage. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these identified drilling locations depends on a number of factors, including commodity prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling conditions, drilling results, lease expirations, gathering system, marketing and transportation constraints, regulatory approvals, urban growth and other factors. If commodity prices become depressed or decline materially from current levels, the number of locations would decrease as increasing numbers of locations would become uneconomic, and any such decrease may be significant. Even to the extent any locations remain capable of economic production, we may determine not to drill such locations until commodity prices recover. Because of these uncertain factors, we do not know if the identified drilling locations will ever be drilled or if we will be able to produce natural gas and NGLs from these drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acreage on which some of the identified locations are located, the leases for such acreage will expire. Therefore, our actual drilling activities may materially differ from those presently identified.

Part of our strategy involves drilling using the latest available horizontal drilling and completion techniques, which involves risks and uncertainties in their application.

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

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.

Water is an essential component of both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local landowners and other sources for use in our operations. Some areas in which we have operations have experienced drought conditions that could result in restrictions on water availability or use. Such drought conditions and water stress may become more frequent or intense as a result of climate change. If we are unable to obtain water to use in our operations from local sources or are unable to transport and store such water, we may be unable to economically produce natural gas and NGLs in the affected areas, which could have an adverse effect on our financial condition, results of operations and cash flows.

The unavailability or high cost of equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our development and exploitation plans on a timely basis and within budget, and consequently could adversely affect our anticipated cash flow.

We utilize third-party services to maximize the efficiency of our operations. The cost of oilfield services typically fluctuates based on demand for those services. While we currently have excellent relationships with oilfield service companies, there is no assurance that we will be able to contract for such services on a timely basis or that the cost of such services will remain at a satisfactory or affordable level. Shortages, quality or the high cost of equipment, supplies or personnel could delay or adversely affect our development and exploitation operations, which could have a material adverse effect on our business, financial condition or results of operations.

We have limited control over activities on properties we do not operate, which could reduce our production and revenues.

As of June 30, 2024, we operated approximately 97% of our net (78% of our gross) acreage. With respect to our natural gas midstream business, we do not operate the NEPA midstream entities, and in the

Barnett, during the six months ended June 30, 2024, approximately 22% of our gross operated production volumes were gathered and processed by our owned and operated system. We have limited control over properties and midstream facilities which we do not operate or do not otherwise control operations. If we do not operate or otherwise control the properties and midstream facilities in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of the underlying properties. The failure of an operator of wells in which we own a non-operating interest or an operator of midstream facilities in which we have an interest to adequately perform operations, an operator's financial difficulties, including as a result of price volatility or an operator's breach of the applicable agreements, could reduce our production and revenues. The success and timing of the drilling and development activities on properties operated by others, as well as the midstream activities with respect to our assets, therefore, depends upon a number of factors outside of our control, including the operator's timing and amount of capital expenditures, expertise and financial resources, inclusion of other participants in drilling wells and use of technology.

Risks Related to Our Power Generation Business

We operate our power generation business through a joint venture which we do not control.

We and BPPUS each have a 50% interest in the BKV-BPP Power Joint Venture. For the six months ended June 30, 2024 and 2023, there were total losses in the BKV-BPP Power Joint Venture of $23.0 million and $14.3 million, respectively. For the years ended December 31, 2023, 2022 and 2021, our interest in the earnings on the BKV-BPP Power Joint Venture represented approximately 1.7%, 0.8% and 0.2% of our revenues, which includes derivative gains (losses), net, respectively.

In accordance with the terms of the Limited Liability Company Agreement of BKV-BPP Power (the "BKV-BPP Power LLC Agreement"), the BKV-BPP Power Joint Venture is managed by a board of managers (the "Power JV Board") consisting of eight members, four of which are appointed by us and four of which are appointed by BPPUS. Consequently, BKV-BPP Power may not take certain material actions without the consent of BPPUS. For example, without the prior consent of BPPUS, the BKV-BPP Power Joint Venture may not:

- make distributions or determine the amount of cash to be distributed;
- make capital expenditures, including acquisitions; or
- incur indebtedness in an amount greater than $1,500,000.

See "*Certain Relationships and Related Party Transactions — BKV-BPP Power Joint Venture — BKV-BPP Power Limited Liability Company Agreement.*"

We face certain risks associated with shared control, and BPPUS may at any time have economic, business or legal interests or goals that are inconsistent with ours.

We may be required to make additional capital contributions to the BKV-BPP Power Joint Venture.

In addition, we may be required to make additional capital contributions to fund items approved in the annual budget or other matters approved by the Power JV Board. We do not control the timing or the amount which we may be required to contribute. If we fail to make additional capital contributions to BKV-BPP Power, as approved by the Power JV Board, such failure could be deemed an event of default under the BKV-BPP Power LLC Agreement. If an event of default occurs, the non-defaulting party will be entitled to (i) sell the assets of the joint venture and dissolve the joint venture on reasonable terms deemed acceptable to the Power JV Board, (ii) obtain specific performance of the non-defaulting party's obligations, and/or (iii) exercise any other right or remedy provided in law or in equity. If we default on any obligation to make an additional capital contribution to BKV-BPP Power and any of these events were to occur, it could have a material adverse effect on the BKV-BPP Power Joint Venture and on our business, financial condition, results of operations and cash flows.

Operation of electric generation facilities involves significant risks and hazards customary to the power industry that could have a material adverse effect on our business, financial condition, results of operations and cash flows.

The ongoing operation of the Temple Plants involves risks that include performance below expected levels of output or efficiency, as well as the unavailability of key equipment or breakdown or failure of equipment or processes (including an inability to obtain key equipment from Siemens natural gas generators and steam turbines and Benson heat recovery steam generators, which are used by the Temple Plants), due to wear and tear, latent defect, design error or operator error or force majeure events, among other things. Unplanned outages of generating units, including extensions of scheduled outages due to mechanical failures or other problems, occur from time to time and are an inherent risk of the business. Unplanned outages typically increase operation and maintenance expenses and capital expenditures and may reduce revenue available to be distributed to BPPUS and us as a result of selling fewer megawatt hours or require us to incur significant costs as a result of obtaining replacement power from third parties in the open market to satisfy forward power sales obligations. Our inability to operate the BKV-BPP Power electric generation assets efficiently, manage capital expenditures and costs and generate distributions from the Temple Plants could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Maintenance, expansion and refurbishment of electric generation facilities involve significant risks that could result in unplanned power outages or reduced output.

The Temple Plants may require periodic upgrading and improvement. Any unexpected operational or mechanical failure, including failure associated with breakdowns and forced outages, could reduce the facility’s generating capacity below expected levels, reducing potential cash distributions to BPPUS and us. Unanticipated capital expenditures associated with maintaining, upgrading or repairing our facility may also reduce profitability.

If we make any major modifications to Temple I or Temple II, we may be required to install the best available control technology or to achieve the lowest achievable emission rates as such terms are defined under and determined pursuant to the new source review provisions of the Clean Air Act (“CAA”) at the time of such modifications. Any such modifications could likely result in substantial additional capital expenditures. We may also choose to repower, refurbish or upgrade our facility based on our assessment that such activity will provide adequate financial returns. Such facility requires time for development and capital expenditures before commencement of commercial operations, and key assumptions underpinning a decision to make such an investment may prove incorrect, including assumptions regarding construction costs, timing, available financing and future fuel and power prices. These events could have a material adverse effect on the BKV-BPP Power Joint Venture, and thus on our business, financial condition, results of operations and cash flows.

The Temple Plants may operate, wholly or partially, without long-term power sales agreements.

The Temple Plants may operate without long-term power sales agreements for some or all of their generating capacity and output and therefore be exposed to market fluctuations. Without the benefit of long-term power sales agreements for the facility, we cannot be sure that the BKV-BPP Power Joint Venture will be able to sell any or all of the power generated by the facility at commercially attractive rates or that either facility will be able to operate profitably. This could lead to less predictable revenues, future impairments of either facility’s property, plant and equipment or the closing of the facility, resulting in economic losses and liabilities, which could have a material adverse effect on the BKV-BPP Power Joint Venture, and thus on our business, financial condition, results of operations and cash flows.

We do not currently supply our own natural gas directly to Temple I, Temple II or their firm natural gas storage service at the Bammel storage facility. We cannot assure you that we will be successful in the future in obtaining the commercial contracts necessary to facilitate direct delivery of our natural gas production to Temple I on commercially reasonable terms or at all.

We cannot assure you that we will succeed in any effort to establish midstream contracts that would allow us to supply our own natural gas directly to Temple I, Temple II or their firm natural gas storage service at the Bammel storage facility. Although the physical infrastructure exists to supply our own natural gas directly to the Temple Plants and the Bammel storage facility, our ability to utilize that infrastructure depends on whether we can successfully negotiate and enter into new midstream contracts on satisfactory terms or at all. If we fail to enter into such contracts on satisfactory terms or at all, we may be unable to achieve the synergistic cost savings we anticipated in connection with the BKV-BPP Power Joint Venture, which could have a material adverse effect on the BKV-BPP Power Joint Venture, and thus on our business, financial condition, results of operations and cash flows.

BKV-BPP Power may enter into financially settled Heat Rate Call Options ("HRCOs") that may expose it to basis and buyback risk in its operations.

To reduce its exposure to fluctuations in the market price of electricity and natural gas, BKV-BPP Power may enter into financially settled HRCOs, which are contracts for the financial purchase and sale of power based on a floating price of natural gas at a predetermined location using a predetermined conversion factor, or heat rate, required to turn the fuel input into electricity. BKV-BPP Power is exposed to basis risk in its operations when its derivative contracts settle financially, and it delivers physical electricity on different terms. For example, if BKV-BPP Power enters into an HRCO, it hedges its electricity production based on an agreed price for that electricity, but physical electricity must be delivered to delivery points in the market it serves. BKV-BPP Power is exposed to basis risk between the hub price specified in the HRCO and the price that it receives for the sales of physical electricity. BKV-BPP Power attempts to hedge basis risk where possible, but hedging instruments are sometimes not economically feasible or available in the quantities that it requires. BKV-BPP Power's hedging activities do not provide it with protection for all of its basis risk and could result in economic losses and liabilities, which could have a material adverse effect on the BKV-BPP Power Joint Venture, and thus on our business, financial condition, results of operations and cash flows.

Additionally, by using derivative instruments to economically hedge exposure to changes in power prices, we could limit the benefit we would receive from increases in the power prices, which could have an adverse effect on our financial condition. For example, as of June 30, 2024, BKV-BPP Power had unrealized losses of $112.0 million on our derivative instruments as a result of increased power prices; of the $112.0 million, $59.5 million of these losses pertain to four open HRCOs. In the event BKV-BPP Power enters into an HRCO and is not able to satisfy its obligations, it must purchase power at prevailing market price to satisfy the HRCO. Likewise, increases in power pricing could limit the benefit we receive under HRCOs and may result in losses. Either such event could have a material adverse effect on the BKV-BPP Power Joint Venture, and thus on our business, financial condition, results of operations and cash flows.

Our costs, results of operations, financial condition and cash flows could be adversely impacted by the disruption of the fuel supplies necessary to generate power at Temple I or Temple II, whether as a result of failure of contractual counterparties, disruption in fuel delivery infrastructure or otherwise.

Delivery of natural gas to fuel the Temple Plants is dependent upon the infrastructure (including natural gas pipelines) available to serve such generation facilities as well as upon the continuing financial viability of contractual counterparties. As a result, the BKV-BPP Power Joint Venture is subject to the risks of disruptions or curtailments in the production of power at our generation facilities if a counterparty fails to perform or if there is a disruption in the fuel delivery infrastructure. Any such disruptions or curtailments could have a material adverse effect on the BKV-BPP Power Joint Venture, and thus on our business, financial condition, results of operations and cash flows.

Risks Related to Our Retail Power Business

We operate our retail power business through a joint venture which we do not control.

Our retail energy business is operated through BKV-BPP Retail, a wholly owned subsidiary of the BKV-BPP Power Joint Venture in which we and BPPUS each have a 50% interest.

We face certain risks associated with shared control, and BPPUS may at any time have economic, business or legal interests or goals that are inconsistent with ours. For additional information, see "— *Risks Related to Our Power Generation Business — We operate our power generation business through a joint* *venture which we do not control,*" and "*Certain Relationships and Related Party Transactions — BKV-BPP Power Joint Venture — BKV-BPP Power Limited Liability Company Agreement.*"

Our retail power business operates in a highly competitive environment, which may make it difficult to grow without reducing prices or incurring additional costs.

Our retail business faces substantial competition from other retail electric providers. As a result, we may be forced to reduce prices or incur increased acquisition costs in order to attract and maintain customers. Present and future competitors may have greater name recognition, long-standing customer and broker relationships, greater-financial strength, or other resources that could put us at a disadvantage.

Our retail power business is subject to market price risk.

Our retail business is required to purchase sufficient energy and ancillary services at wholesale to serve its retail customers. Although wholesale prices fluctuate based on market conditions, our retail business has contracted to provide 100% of our customers with fixed power prices. As a result, BKV-BPP Retail is exposed to fluctuations in wholesale energy and ancillary service prices. BKV-BPP Retail attempts to hedge this exposure where possible, but hedging instruments are sometimes not economically feasible or available in the quantities that it requires, certain components of energy prices are not able to be hedged at all, and hedge providers could fail to perform. BKV-BPP Retail's hedging activities do not provide it with protection for all of its risks, and price fluctuations, including those caused by transmission congestion or extreme weather, could result in economic losses and liabilities, which could have a material adverse effect on BKV-BPP Retail.

Our retail power business is vulnerable to changes in law, regulation, or market structure resulting in unanticipated costs that cannot be passed through to customers.

Our retail business operates in a highly regulated environment. It is directly regulated by both the PUCT and ERCOT. Changes in regulation could create increased costs that BKV-BPP Retail might be unable to pass through to customers, particularly those on fixed-priced contracts. For example, ERCOT introduced a new ancillary service product — ERCOT Reserve Contingency Service ("ECRS") — in June 2023. Although ERCOT began assessing ECRS charges to BKV-BPP Retail, the PUCT prevented retail suppliers such as BKV-BPP Retail from passing these costs onto existing customers on fixed price contracts. Future changes in law or regulation resulting in increased costs could impact our retail business.

Our retail business, including our relationship with our supplier, is dependent on access to capital and liquidity.

Our business involves entering into contracts to purchase large quantities of electricity. Because of seasonal fluctuations, we often have to purchase electricity and hedges in advance and finance the purchases until we can recover such amounts from our customers. Aside from our trades with BKV-BPP Power, we rely on an energy supplier to sleeve our energy and hedge purchases. Should we be unable to renew this agreement or should our energy supplier experience a credit rating decrease, our ability to affordably purchase energy and hedges could be impacted. Further, any difficulty obtaining credit or liquidity on commercially reasonable terms could impact our retail business.

Our retail business depends on our ability to attract and retain personnel with retail market experience.

Our success depends on key members of our management team, the loss of whom could disrupt our business operations. Further, our business is required by the PUCT to have one or more officers or managers with at least 15 years of combined experience in the competitive energy industry. The loss of certain key personnel could impact our ability to continue operating a retail electric business and could endanger our retail electric provider ("REP") certificate.

Our retail business depends on maintaining regulated permits and any loss of these permits would adversely affect our business.

Our business requires a REP certificate from the PUCT and a load serving entity ("LSE") registration and qualified scheduling entity ("QSE") registration with ERCOT. Both the PUCT and ERCOT impose various requirements to maintain these permits. Any negative publicity regarding the retail industry in general could result in agencies or the state legislature seeking to further regulate the retail business and an increase in our compliance burdens. Further customer complaints and compliance violations can negatively affect our relationship with the PUCT and potentially endanger our REP certificate. Any loss of our REP certificate, LSE registration or QSE registration would prevent us from continuing to participate in the retail market.

Risks Related to Our CCUS Business

Our ability to establish and operate large scale CCUS projects is subject to numerous risks and uncertainties. We may be unsuccessful in developing our CCUS business as currently anticipated, either wholly or in significant measure.

A key element of our business strategy includes the development of a CCUS business. We have limited experience in the development and operation of a CCUS business, which poses different challenges and risks than our existing upstream and natural gas midstream businesses. We may be unable to execute on our business plans, demand for these new services may not develop on a large or economic scale or we may fail to operate our CCUS business effectively. Our CCUS business may also present novel issues in law, taxation, emission offset accounting and accreditation, safety or environmental policy, subsurface storage, supply chain, project design and other areas that we may not be able to manage effectively or that could change considerably. Management's assessment of the risks in this line of business may be inexact and not identify or resolve all the problems that we may face. If we are unsuccessful in timely developing a commercially successful CCUS business, our future growth and results of operations may be materially and adversely affected, and we may be unable to realize much of our current business plans, including timely reaching our goal of net zero Scope 1, 2 and 3 emissions across our owned and operated upstream businesses, either by the dates projected or at all.

Due to the early stage nature of CCUS projects and the sector generally, CCUS projects face considerable risks. In particular, the Barnett Zero Project, our BKV dCarbon Ventures CCUS project with EnLink, and the Cotton Cove Project face, and any of our potential CCUS projects in the future, including the pipeline of CCUS projects currently under evaluation, will face, operational, technological, regulatory and financial risks (including the risk that EnLink, BPPUS or any of our other future counterparties to a CCUS project, will not meet their financial or performance obligations with respect to the CCUS project).

Although we have identified fifteen potential CCUS projects in addition to the Barnett Zero Project and Cotton Cove Project, these additional potential projects are in different stages of the evaluation process. In most cases, emitters have required extended periods of time to evaluate potential projects and participate in negotiations. We have not entered into the definitive agreements necessary to execute any of the other fifteen potential projects we have identified and, as such, we cannot assure you that any of those fifteen potential projects will reach FID or be completed. Additionally, we cannot assure you we will be able to source and identify additional emitters willing to enter into CCUS project agreements with us. We may not receive 100% of the environmental attributes associated with CCUS projects funded in whole or in part by third parties, and, in such cases, we expect to have the right to purchase such environmental attributes BKV would not otherwise receive. Ultimately, we will be able to apply only such portion of the sequestered emissions to offset our own GHG emissions that corresponds to the percentage of environmental attributes BKV receives or purchases. Our stated goals of timely achieving net zero Scope 1, 2 and 3 emissions from our owned and operated upstream businesses are dependent, in part, on being able to commercially develop our existing pipeline of CCUS projects.

Further, our ability to successfully operate the Barnett Zero Project with EnLink, or successfully develop the Cotton Cove Project with BPPUS and any future potential CCUS projects, depends on a number of factors that we are not able to fully control, including the following:

- Commercial scale carbon capture is an emerging sector, and there are not substantial precedents to gauge the likely range of structures or economic terms that will be necessary to reach agreeable terms.
- CCUS injection wells are currently subject to overlapping state and federal jurisdiction and new and evolving regulatory frameworks. The timetable for issuance of permits and authorizations required

for a CCUS project is uncertain and could entail a multi-year process. The issuance of permits may be subject to regulatory delays and third-party challenges. We cannot guarantee that we will be able to obtain necessary permits on a timely basis, on favorable terms, or at all.

- As CCUS and carbon management represent an emerging sector, regulations may evolve rapidly, which could impact the feasibility of one or more of our anticipated projects. To the extent regulatory requirements are amended or more stringently enforced, or new regulatory requirements are added, we may incur additional delays and/or costs in the pursuit of one or more of our carbon capture projects, which costs may be material or may render any one or more of our projects uneconomical.
- We may not own the pore space at all of our CCUS project sites, which may require us to enter into agreements with multiple owners to secure the necessary real estate rights for the extent of the geologic formation that may be utilized. The failure to obtain necessary pore space rights from all owners, in the absence of a state law mechanism for eminent domain or forced amalgamation, could have a material adverse effect on any proposed CCUS project.
- Robust monitoring, recordkeeping and reporting required in connection with CCUS projects may increase the costs of such operations. Different methodologies may be required to satisfy various regulatory and non-regulatory requirements regarding GHG emissions/sequestration at one or more of our projects, including, but not limited to, compliance with the EPA mandatory Greenhouse Gas Reporting Program.
- CCUS injection wells and carbon sequestration reservoirs or formations may experience integrity, operating or boundary breaches resulting in additional costs, liability and risk from undesired well casing pressures, breakthrough of injected CO_2 to the land surface, CO_2 plume migration outside of expected or modeled results into undesired or unwanted surface or subsurface areas, well integrity issues or various other outcomes.
- Carbon capture may be viewed as a pathway to the continued use of fossil fuels, notwithstanding that CO_2 emissions are intended to be captured. There may be organized opposition to carbon capture, including our projects, alleging concerns relating to the environment, environmental justice, health or safety, or the federal and state governments may cease supporting carbon capture and sequestration.
- In addition to the BKV-BPP Cotton Cove Joint Venture, the development of a CCUS project may require us to enter into long-term joint ventures with large carbon emitters (which may need to finance and build, often over a multi-year period, the equipment to capture CO_2 emissions from various industrial processes) and operators of infrastructure for transporting CO_2 (or other GHGs), and we may not be able to do so on agreeable terms or at all.

The development of our CCUS business is expected to require material capital investments.

We estimate the aggregate investment required to develop the seventeen identified actual and potential CCUS projects to be between approximately $1.3 – 1.8 billion between now and the end of 2030. We currently estimate the total investment required for the Barnett Zero Project to be approximately $36.0 million and the total investment required for the Cotton Cove Project to be approximately $17.6 million, of which we will be required to contribute approximately $9.0 million, as discussed in "*Certain Relationships and Related Party Transactions — BKV-BPP Cotton Cove Joint Venture — BKV-BPP Cotton Cove Limited Liability Company Agreement*."

Our CCUS projects are expected to have material capital requirements, and we expect to fund up to 50% of these CCUS projects from a variety of external sources, which may include joint ventures, project-based equity partnerships and federal grants, with the remaining capital needs being funded with cash flows from operations. We anticipate that some of these project costs will be borne by third-party investors in these projects, including emitters, landowners and other stakeholders. However, there is no certainty that we will be able to obtain external funding on a timeline sufficient to achieve our goals, on commercially reasonable terms or at all. Our access to external funding depends on a number of factors, including general market conditions, potential investors' confidence in our CCUS program, business model, growth potential and our current and expected future earnings as well as the liquidity needs of the external funding sources themselves. We may face intense competition from a variety of other companies and financing structures for such limited investment capital. If we are unable to obtain a sufficient level of external funding for our

CCUS projects, we may be required to abandon or materially delay certain projects, which in turn could negatively impact our ability to realize our business plan or to reach our near term and long term net zero goals on our anticipated time frame or at all. We similarly may not be able to reach our positive net income goals for our CCUS business on the timeline we have predicted, which may likewise adversely impact our business or financial condition. CCUS activities subject us to the financial risks of rising costs of equipment and capital, possible delays in acquiring them, along with the financial impact of our expending capital on these activities in advance of realizing any CCUS cash flows, any of which could negatively impact our financial condition and operational results in future periods.

To the extent CO_2 transportation pipelines are not already present in proposed project areas, or if they do not extend to one or more of our project sites, we may be required to convert existing non-CO_2 pipelines, or build new CO_2 pipelines or lateral connections, which will require more time before we can bring together captured CO_2 emissions and transport them to appropriately tested and prepared sequestration sites, require much larger capital expenditures and may be subject to various environmental and other permitting requirements and authorizations as well as third-party easements that could be difficult or costly to obtain, which may render one or more projects uneconomical or impractical. The availability of eminent domain for carbon capture pipelines varies by state and can be highly controversial; there may be organized opposition to eminent domain for carbon capture pipelines, including those associated with our projects, from environmental or landowner groups. Additionally, even in areas where such pipelines are in place, our use of them may require reaching agreements on CO_2 transportation with operators of the pipelines.

Additionally, the development of CCUS projects through our current or potential future joint ventures involves risks not present in investments in which a third party is not involved, including the possibility that:

- we and a co-venturer or partner may reach an impasse on a major decision that requires the approval of both parties;
- we may not have exclusive control over the development, financing, management and other aspects of joint venture, which may prevent us from taking actions that are in our best interest but opposed by a co-venturer or partner;
- a co-venturer or partner may encounter liquidity or insolvency issues or may become bankrupt, which may mean that we and any other remaining co-venturers or partners generally would remain liable for the joint venture’s liabilities;
- a co-venturer or partner may at any time have economic or business interests or goals that are or may become inconsistent with ours;
- a co-venturer or partner may be in a position to take action contrary to our instructions, requests, policies or investment objectives, including our current policy with respect to maintaining our qualification for enhanced Section 45Q tax credits under the Code;
- a co-venturer or partner may take actions that subject us to liabilities in excess of, or other than, those contemplated;
- in certain circumstances, we may be liable for actions of our co-venturer or partner;
- our joint venture agreements may restrict the transfer of a co-venturer’s or partner’s interest or otherwise restrict our ability to sell the interest when we desire or on advantageous terms;
- our joint venture agreements may contain buy-sell provisions pursuant to which one co-venturer or partner may initiate procedures requiring the other co-venturer or partner to choose between buying the other co-venturer’s or partner’s interest or selling its interest to that co-venturer or partner;
- if a joint venture agreement is terminated or dissolved, we may not continue to own or operate the interests or investments underlying the joint venture relationship or may need to purchase such interests or investments at a premium to the market price to continue ownership; or
- disputes between us and a co-venturer or partner may result in litigation or arbitration that could increase our expenses and prevent our management from focusing their time and attention on our business.

Any of the above could materially and adversely affect our ability to execute on our CCUS strategy, the value of any CCUS project we develop through a current or potential future joint venture and potentially have a material adverse effect on our ability to reach our near term and long term net zero goals on our anticipated time frame or at all, as well as on our liquidity, financial condition and results of operations.

We operate the Cotton Cove Project through a joint venture that requires the consent of BPPUS for certain material actions.

The BKV-BPP Cotton Cove Joint Venture is owned 51% by BKV dCarbon Ventures and 49% by BPPUS and was formed on August 25, 2023 to own the Cotton Cove Project. In accordance with the terms of the Limited Liability Company Agreement of BKV-BPP Cotton Cove (the "BKV-BPP Cotton Cove LLC Agreement"), the BKV-BPP Cotton Cove Joint Venture is managed by a board of managers (the "Cotton Cove JV Board") consisting of six members, four of whom are appointed by BKV dCarbon Ventures and two of whom are appointed by BPPUS. Certain material actions require the unanimous consent of the Cotton Cove JV Board and consequently, BKV-BPP Cotton Cove may not take certain material actions without the consent of BPPUS, as discussed in "*Certain Relationships and Related Party Transactions — BKV-BPP Cotton Cove Joint Venture — BKV-BPP Cotton Cove Limited Liability Company Agreement.*"

We face certain risks associated with shared control, and BPPUS may at any time have economic, business or legal interests or goals that are inconsistent with ours.

The commercial viability of our CCUS projects depends, in part, on certain financial and tax incentives provided by the U.S. federal government.

The economics of CCUS projects depend on financial and tax incentives that could be changed or terminated and that may not currently be sufficient for our CCUS projects to be economical. For example, our qualification for enhanced Section 45Q tax credits is dependent upon our ability to meet certain wage and apprenticeship requirements. If we are unable to obtain the Section 45Q tax credits included in our financial assumptions, many of our proposed CCUS projects may no longer be commercially viable and may not be completed. We cannot assure you that we will be successful in obtaining any or all of the Section 45Q tax credits currently available. Additionally, we may not receive 100% of the Section 45Q tax credits associated with CCUS projects funded in whole or in part by third parties and, in such cases, will receive only a corresponding percentage of the anticipated Section 45Q tax credits associated with such projects.

CCUS projects will require storage of CO_2 in subterranean reservoirs over long periods of time. If accidental releases or subsurface migration of CO_2 from our CCUS activities were to occur in the course of operating one or more of our CCUS sites, there is the risk of government recapture of Section 45Q tax credits previously claimed by or issued to us, as well as a risk of trespass or other tort or property claims related to the accidental release or migration of CO_2 beyond the permitted boundaries of any anticipated project as well as the potential for fines and penalties for violations of environmental requirements.

A successful CCUS project in the United States must comply with what we anticipate will be a stringent regulatory scheme involving multiple federal and state permits applicable to the subsurface injection of CO_2 for geologic sequestration. Moreover, when we are the operator of a CCUS project, we must demonstrate and maintain levels of financial assurance sufficient to cover the cost of corrective action, injection well plugging, post-injection site care and site closure and emergency and remedial response. There is no assurance that we will be successful in obtaining permits or adequate levels of financial assurance for one or more of our CCUS projects or that permits can be obtained on a timely basis, whether due to difficulty with the technical demonstrations required to obtain such permits, public opposition, undeveloped regulatory framework or otherwise.

There can be no assurances that we will be able to execute on our CCUS strategy and successfully operate the Barnett Zero Project with EnLink in the Barnett, or successfully develop the Cotton Cove Project with BPPUS or any future CCUS projects and any failure to do so in whole or in any significant part could have a material adverse effect on our ability to reach our near term and long term net zero goals on our anticipated time frame or at all, as well as on our liquidity, financial condition and results of operations.

Risks Related to Our Midstream Business

Midstream operations are complex activities which present certain risks that could adversely affect our business, financial condition or results of operations.

In operating our midstream and production facilities, from time to time we experience certain issues and encounter risks, including, for example, mechanical and instrument or tool failures; loss of well, pressure vessel, tank or other related equipment control and associated hydrocarbon release and/or natural gas clouds; loss or compromise of casing integrity during production; unwanted casing pressure or fluid migration during production operations; unwanted migration of sequestered carbon dioxide or other fluids in injection wells; temporary and permanent surface facility operations and associated pressure and hydrocarbon hazards; surface overpressure events and other hazards resulting from machinery (horsepower), equipment or well pressure; fines and violations related to relevant laws and regulations; fires and explosions; pipeline loss of containment due to integrity issues, pipeline strikes or other reasons and associated hydrocarbon release; personnel safety hazards such as working at heights, driving or equipment operation, energy isolation, excavation and trenching and more; major damage or malfunction to key equipment or processes; structural damage and collapse to equipment and machinery; in certain instances, close proximity of operations to residences and/or communities; among other typical midstream and production facilities challenges and risks.

We depend on our natural gas midstream system for the gathering and processing of a substantial percentage of our natural gas production.

As of June 30, 2024, we own and operate approximately 778 miles of gathering pipeline, 65 midstream compressors and one amine processing unit. In the event that our natural gas midstream system is unable to process our natural gas production, or its operations are otherwise disturbed or curtailed, we could experience a disruption in our ability to transport our natural gas production, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Construction of midstream projects subjects us to risks of construction delays, cost over-runs, limitations on our growth and negative effects on our financial condition, results of operations, cash flows and liquidity.

From time to time, we may plan and construct midstream projects, some of which may take a number of months before commercial operation, such as construction of natural gas, NGL and produced water gathering or transportation systems and construction of related facilities. These projects are complex and subject to a number of factors beyond our control, including delays from third-party landowners, the permitting process, government and regulatory approval, compliance with laws, unavailability of materials, labor disruptions, environmental hazards, financing, accidents, weather and other factors. Any delay in the completion of these projects could have a material adverse effect on our financial condition, results of operations and cash flows. The construction of these midstream facilities requires the expenditure of significant amounts of capital, which may exceed our estimated costs. Estimating the timing and expenditures related to these development projects is very complex and subject to variables that can significantly increase expected costs. Should the actual costs of these projects exceed our estimates, our liquidity and financial condition could be adversely affected. This level of development activity requires significant effort from our management and technical personnel and places additional requirements on our financial resources and internal financial controls. We may not have the ability to attract and/or retain the necessary number of personnel with the skills required to bring complicated projects to successful conclusions.

We do not own all of the land on which our pipelines and other midstream facilities are located, which could disrupt our operations.

We do not own all of the land on which our pipelines and other midstream facilities are located, and we are therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights-of-way or leases or if such rights-of-way or leases lapse or terminate. We sometimes obtain the rights to land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts, leases, or otherwise, could cause us to cease operations on the affected land, increase costs related to continuing operations elsewhere, and reduce our revenue.

Risks Related to Our Business Generally

Substantially all of our oil and gas and midstream properties are concentrated in Texas and Northeast Pennsylvania, making us vulnerable to risks associated with operating in only two geographic areas.

Substantially all of our oil and gas and midstream properties are located in Texas and Northeast Pennsylvania. As a result of this geographic concentration, an adverse development in the natural gas, NGL and oil and/or midstream business in either or both of these operating areas could have a greater impact on our financial condition, results of operations and available cash than if we were more geographically diversified. Due to the concentrated nature of our properties, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in these areas caused by governmental regulation, processing or transportation capacity constraints, water shortages or other drought related conditions, availability of equipment, facilities, personnel or services market limitations or interruption of the processing or transportation of natural gas, NGLs and oil.

In addition, the weather in these areas can be extreme and can cause interruption in our operations. Severe weather can result in damage to our facilities entailing longer operational interruptions and significant capital expenditures. For instance, during 2021, Winter Storm Uri in Texas resulted in over 1.5 Bcfe of curtailed production and significant freezing and associated downtime across our facilities and equipment.

The effect of fluctuations on supply and demand may become more pronounced within specific geographic natural gas, NGL and oil producing areas, which may cause these conditions to occur with greater frequency or magnify the effects of these conditions. A number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition, results of operations and cash flows.

A financial crisis or deterioration in general economic, business or industry conditions could materially adversely affect our results of operations and financial condition.

Concerns over global economic conditions, instability in the banking sector, stock market volatility, energy costs, geopolitical issues, inflation and U.S. Federal Reserve interest rate increases in response, the availability and cost of credit, and slowing of economic growth in the United States and fears of a recession have contributed and may continue to contribute to economic uncertainty and diminished expectations for the global economy.

Our business has also been impacted by economic conditions and disruptions in global financial markets such as reduced energy demand, increased prices due to the impacts of pandemics, inflation, and labor shortages. There was uncertainty during 2023 with potential economic downturns or recessions in parts of the United States and globally, which continues into 2024 with global conflicts such as the Russia-Ukraine and Israel-Hamas wars. Due to uncertainty in inflation, we may continue to see global, industry-wide supply chain disruptions and widespread shortages of labor, materials and services. Such shortages have resulted in our facing significant cost increases for labor, materials and services, and we expect these shortages and cost increases to continue. We are currently in a period of declining natural gas prices; however, the cost of labor, materials, and services remains high and may not adjust downward in proportion to increase in natural gas prices. We cannot predict the future inflation rate but to the extent inflation remains elevated, we may experience further cost increases in our operations, including costs for drill rigs, workover rigs, hydraulic fracturing fleets, tubulars and other well equipment, as well as increased labor costs. If we are unable to recover from higher costs through increases in commodity prices or from our current revenue stream, then our estimates of future reserves, impairment assessments of natural gas and oil properties, and values of properties in purchase and sale transactions may all be significantly impacted. Although macroeconomic inflation is easing, these inflationary pressures may have an impact on our liquidity position when combined with the impact of rising interest rates on our variable rate debt. We expect to continue to achieve our business strategy by remaining vigilant in maintaining a disciplined financial strategy and in optimizing the value of our core business. We will also continue to monitor the impacts of inflation and commodity price volatility and the effects on our business, including to our customers and our partners.

Similarly, we cannot predict the impact that high market volatility and instability in the banking sector could have on economic activity and our business in particular. The failure of banks and financial institutions and measures taken, or not taken, by governments, businesses and other organizations in response to these events could adversely impact our business, financial conditions and results of operations.

In addition, continued hostilities between Russia and Ukraine and Israel and Hamas and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the economies of the United States and other countries. The ongoing conflicts between Russia and Ukraine and Israel and Hamas could continue to have repercussions globally and in the United States by continuing to cause uncertainty, not only in the natural gas, NGL and oil markets, but also in the capital markets. Such uncertainty could result in stock price volatility and supply chain disruptions, as well as higher natural gas, NGL and oil prices which could potentially result in increased inflation worldwide and could negatively impact demand for natural gas, NGLs, oil and electricity.

Concerns about global economic growth can result in a significant adverse impact on global financial markets and commodity prices. In addition, any financial crisis may cause us to face limitations on our ability to borrow under our debt agreements, service our debt obligations, access the debt and equity capital markets and complete asset purchases or sales and may cause increased counterparty credit risk on our derivative instruments and such counterparties to cause us to post collateral guaranteeing performance.

Further, if there is a financial crisis or the economic climate in the United States or abroad deteriorates, worldwide demand for hydrocarbon-based products could materially decrease, which could impact the price at which natural gas and NGLs from our properties are sold, affect the ability of vendors, suppliers and customers associated with our properties to continue operations and ultimately materially adversely impact our results of operations and financial condition. If a material adverse change occurs in our business such that an event of default occurs under our debt agreements, the lenders under such agreements may be able to accelerate the maturity of our debt.

Events outside of our control, including an epidemic or outbreak of an infectious disease, such as COVID-19, or the threat thereof, could have a material adverse effect on our business, liquidity, financial condition, results of operations and cash flows and ability to pay dividends on our common stock.

We face risks related to pandemics, epidemics, outbreaks or other public health events, or the threat thereof that are outside of our control, and could significantly disrupt our business and operational plans and adversely affect our liquidity, financial condition, results of operations and cash flows. The COVID-19 pandemic adversely affected the global economy and resulted in unprecedented governmental actions in the United States and countries around the world, including, among other things, social distancing guidelines, travel restrictions and stay-at-home orders, among other actions, which caused a significant decrease in activity in the global economy and the demand for oil, and to a lesser extent, natural gas and NGLs.

The nature, scale and scope of the above-described events, combined with the uncertain duration and extent of governmental actions, prevent us from identifying all potential risks to our business. Additionally, the effects of the COVID-19 pandemic might worsen the likelihood or the impact of other risks already inherent in our business. We believe that the known and potential impacts of the COVID-19 pandemic and related events include, but are not limited to, the following:

- disruption in the demand for natural gas, NGLs and oil and other petroleum products;
- intentional project delays until commodity prices stabilize;
- a potential future downgrade of our credit rating and potentially higher borrowing costs in the future;
- a need to preserve liquidity, which could result in reductions, delays or changes in our capital expenditures;
- supply chain disruptions, resulting in shortages of, and increased pricing pressures on, among other things, equipment, services and labor;

- liabilities resulting from operational delays due to decreased productivity resulting from stay-at-home orders affecting our workforce or facility closures resulting from the COVID-19 pandemic;
- future asset impairments, including impairment of our natural gas and NGL properties and other property and equipment; and
- infections and quarantining of our employees and the personnel of vendors, suppliers and other third parties.

New variants of COVID-19 could cause further commodity market volatility and resulting financial market instability, or any other event described above, and these are variables beyond our control that may adversely impact our operating cash flows, distributions from our unconsolidated affiliate and our ability to access the capital markets.

The success of our business plan depends, in part, on achieving our near term and long term net zero goals on our anticipated time frame.

The development of our CCUS business, as well as the expansion of our “Pad of the Future” program and the effectiveness of our leak detection and repair emissions monitoring program and the BKV-BPP Power Joint Venture’s planned solar facility, are each important factors to our potential ability to achieve our emissions goal of net zero Scope 1 and 2 emissions from our owned and operated upstream and natural gas midstream businesses by the early 2030s and aspirations to offset Scope 3 emissions from our owned and operated upstream and natural gas midstream businesses by the late 2030s. We may not meet our near term or long term goals by our target date or at all. Likewise, our estimated sequestration rates from our CCUS business and our emissions reduction expected from our initiatives and our associated expected emissions offsets and/or other environmental attributes may turn out to be inaccurate. The standards and expectations regarding carbon accounting and the processes for measuring and counting GHG emissions and GHG emission reductions are evolving. Changes in GHG emission accounting methodologies, regulatory changes addressing the use of “net zero” in environmental marketing claims or new developments related to climate science could impact our ability to claim emissions reductions related to our CCUS business or otherwise. For more information, see “*— Risks Related to Environmental, Legal Compliance, and Regulatory Matters*.” As a result, it is possible that factors outside of our control could give rise to the need to restate or revise our emissions reduction goals, cause us to miss them altogether, or limit the impact of success of achieving our goals.

Moreover, our CCUS business and nearly all of our CCUS projects are in the early stages of development. Although we commenced commercial operations with the initial injection of CO_2 waste at the Barnett Zero Project in November 2023, and have reached FID and entered into definitive agreements with respect to the Cotton Cove Project, we have not reached FID with respect to or entered into the definitive agreements necessary to execute any of the other fifteen potential projects described in “*Business — Our Operations — Carbon Capture, Utilization and Sequestration*” and may not be able to reach agreements on terms acceptable to us, or to achieve our projected timeline for commercial operations. In addition, the development of our CCUS business is expected to require material capital investments, and the projected timeline for commercial operations depends on our ability to fund the anticipated capital requirements for the potential projects that we have identified through external funding and revenues from our upstream business. Furthermore, the commercial viability of our CCUS projects depends, in part, on obtaining necessary permits and other regulatory approvals and on our ability to receive our portion of the anticipated Section 45Q tax credits associated with these projects. In particular, we must meet certain wage and apprenticeship requirements in order to qualify for enhanced Section 45Q tax credits.

Our ability to establish and operate large scale CCUS projects is subject to numerous risks and uncertainties, including securing third-party financing, reaching definitive agreements with third parties and obtaining necessary permits and other regulatory approvals, and we may be unable to execute on some or all of these projects, including the projects for which we have reached FID, on the timeline we anticipate, on terms acceptable to us or at all. We may not be successful in developing any of our currently identified potential CCUS projects or others, our actual costs with respect to any CCUS projects may exceed our current estimate and we may not be able to realize the anticipated reductions and offsets in emissions. There can be no assurances that we will be able to execute on our CCUS strategy and successfully operate the Barnett Zero

Project with EnLink, or successfully develop the Cotton Cove Project with BPPUS or any future CCUS projects and any failure to do so in whole or in any significant measure could have a material adverse effect on our ability to meet our Scope 1, 2 and 3 owned and operated upstream and natural gas midstream emissions goals. Even if we are able to successfully develop and operate such projects, we may not receive 100% of the environmental attributes associated with CCUS projects funded in whole or in part by third parties, and, in such cases, we expect to have the right to purchase such environmental attributes BKV would not otherwise receive. Ultimately, we will be able to apply only such portion of the sequestered emissions to offset our own GHG emissions that corresponds to the percentage of environmental attributes BKV receives or purchases, which may negatively impact our net zero strategy, including by delaying or preventing our achievement of net zero. We have already had to extend out the timing for our achievement of our net zero goals and we may have to do so again in the future. Any disputes or ambiguities regarding the right to claim environmental attributes, may also increase the risk of double-counting of such attributes, which may negatively affect our ability to reach our net zero goals and negatively affect perceptions of our operations and products. Additionally, to the extent we meet our emissions reduction goals, they may be achieved through various contractual arrangements, in addition to those described in "*Business — Overview — Our Operations — Path to Net Zero Emissions,*" including the purchase of various credits or offsets that may be deemed to mitigate our emissions impact instead of actual changes in our emissions reduction performance. However, we cannot guarantee that there will be sufficient offsets available for purchase given the increased demand from numerous businesses implementing net zero goals, that the offsets we do purchase will successfully achieve the emissions reductions they represent or that such offsets will be deemed sufficient by third parties to whom we may seek to market our products with certain environmental attributes or product claims. See "— *Risks Related to Our CCUS Business.*"

We may not be able to generate enough cash flow to meet our debt obligations or fund our other liquidity needs.

As of August 12, 2024, we had outstanding debt of $410.0 million, which consisted of (i) $360.0 million in aggregate principal amount of revolving borrowings under the RBL Credit Agreement and (ii) $50.0 million in aggregate principal amount under the BNAC A&R Loan Agreement as described in "*Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Loan Agreements and Credit Facilities — Subordinated Intercompany Loan Agreements.*" We intend to use borrowings under the RBL Credit Agreement for working capital purposes, to fund capital expenditures, for the acquisitions, development and exploration of oil and gas properties and for general company purposes.

In addition to interest expense and principal on our long-term debt, we have demands on our cash resources including, among others, operating expenses and capital expenditures.

Our ability to pay the principal and interest on our long-term debt and to satisfy our other liabilities will depend upon future performance and our ability to repay or refinance our debt as it becomes due. Our future operating performance and ability to refinance will be affected by economic and capital market conditions, fluctuations in commodity prices, results of operations and other factors, many of which are beyond our control. Our ability to meet our debt service obligations also may be impacted by changes in prevailing interest rates, as borrowings under the BNAC A&R Loan Agreement and the RBL Credit Agreement bear interest at floating rates.

We may not generate sufficient cash flow from operations. Without sufficient cash flow, there may not be adequate future sources of capital to enable us to service our indebtedness or to fund our other liquidity needs. If we are unable to service our indebtedness and fund our operating costs, we will be required to adopt alternative strategies that may include:

- reducing or delaying capital expenditures;
- seeking additional debt financing or equity capital;
- selling assets; or
- restructuring or refinancing debt.

We may not be able to complete such alternative strategies on satisfactory terms, if at all. Our inability to generate sufficient cash flows to satisfy our debt obligations and fund our liquidity needs, or to refinance our indebtedness on commercially reasonable terms, would materially and adversely affect our financial condition and results of operations.

We may be unable to achieve or maintain a low target level of indebtedness.

If we receive the requisite consents from our existing lenders, we may incur significant additional indebtedness in the future in order to make acquisitions or to develop our properties or for other general corporate purposes.

Our level of indebtedness could affect our operations in several ways, including the following:

- a significant portion of our cash flows could be used to service our indebtedness;
- a high level of debt would increase our vulnerability to general adverse economic and industry conditions;
- the covenants contained in the agreements governing our outstanding indebtedness limit our ability to borrow additional funds, dispose of assets, pay dividends on our common stock, and make certain investments;
- a high level of debt may place us at a competitive disadvantage compared to our competitors that are less leveraged and therefore, may be able to take advantage of opportunities that our indebtedness would prevent us from pursuing;
- our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry; and
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate, or other purposes.

An increase in our level of indebtedness may further reduce our financial flexibility. Further, a high level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, commodity prices, and financial, business, and other factors affect our operations and our future performance. Many of these factors are beyond our control. We may not be able to generate sufficient cash flows to pay the interest on our debt and future working capital, borrowings, or equity financing may not be available to pay or refinance such debt. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions (including any financial crisis), the value of our assets, and our performance at the time we need capital.

The agreements governing our indebtedness contain restrictive covenants that may limit our ability to respond to changes in market conditions, pursue business opportunities or pay dividends to our stockholders.

The agreements governing our indebtedness contain restrictive covenants that limit our ability to, among other things:

- incur additional debt;
- incur additional liens;
- sell, transfer or dispose of assets;
- merge or consolidate, wind-up, dissolve or liquidate;
- pay dividends and distributions on, or repurchases of, equity;
- make acquisitions and investments, other than direct investments in natural gas, NGL and oil properties and other assets in permitted lines of business;
- enter into certain transactions with our affiliates;
- enter into sale-leaseback transactions;
- make optional or voluntary payment of subordinated debt and certain other debt;

- change the nature of our business;
- change our fiscal year to make changes to the accounting treatment or reporting practices;
- amend constituent documents; and
- enter into certain hedging transactions.

The RBL Credit Agreement contains, and any future debt agreement may contain, covenants that prohibit us from paying dividends on our common stock under certain circumstances. For additional information regarding the restrictions contained in the RBL Credit Agreement on the RBL Borrower's and its restricted subsidiaries' ability to pay dividends to their stockholders (including BKV Corporation), see "*— Risks Related to the Offering and Our Common Stock — The agreements governing our indebtedness impose restrictions on dividend payments*."

In addition, the RBL Credit Agreement requires the RBL Borrower to maintain, and future debt agreements may require us to maintain, compliance with financial ratios and tests.

The requirement that we comply with these provisions may materially adversely affect our ability to react to changes in market conditions, take advantage of business opportunities we believe to be desirable, obtain future financing, fund needed capital expenditures, withstand a continuing or future downturn in our business or pay dividends to our stockholders.

If we are unable to comply with the restrictions and covenants in our debt agreements, there could be an event of default under the terms of such agreements, which could result in an acceleration of repayment and the foreclosure of liens on our assets.

If we are unable to comply with the restrictions and covenants in the BNAC A&R Loan Agreement, RBL Credit Agreement or any future debt agreement or if we default under the terms of the BNAC A&R Loan Agreement, the RBL Credit Agreement or any future debt agreement, there could be an event of default. Our ability to comply with these restrictions and covenants, including meeting any financial ratios and tests, may be affected by events beyond our control. Further, if, after this initial public offering, any person or group (other than Banpu and its controlled affiliates, excluding portfolio companies and operating companies) acquires 35% or more of BKV Corporation's equity interests, or if any person or group acquires a greater percentage of BKV Corporation's equity interests than are then held by Banpu and its controlled affiliates (excluding portfolio companies and operating companies of Banpu), such event will be an event of default under the RBL Credit Agreement, which may result in amounts owed by us thereunder to become immediately due and payable. Banpu has no obligation to maintain any particular percentage of equity ownership in the Company (other than the 180-day lock-up agreement and other restrictions described in "*Shares Eligible for Future Sale*") and may at any time sell all or any portion of its equity interests in us. As a result, we cannot assure that we will be able to comply with these restrictions and covenants or meet such financial ratios and tests. In the event of a default under the BNAC A&R Loan Agreement, RBL Credit Agreement or any future debt agreement, the lenders could terminate their commitments to lend or accelerate the loans and declare all amounts borrowed due and payable. Our obligations under the RBL Credit Agreement are secured by liens on substantially all of BKV Corporation's and the RBL Borrower's assets and those of the RBL Borrower's restricted subsidiaries that guarantee our obligations under the RBL Credit Agreement, and an event of default under the RBL Credit Agreement could result in the foreclosure of such liens. If any of these events occur, our assets might not be sufficient to repay in full all of our outstanding indebtedness and we may be unable to find alternative financing. Even if we could obtain alternative financing, it might not be on terms that are favorable or acceptable to us. Additionally, we may not be able to amend the RBL Credit Agreement or any future debt agreement or obtain needed waivers on satisfactory terms.

Natural gas prices have decreased significantly since January 1, 2023, which caused non-compliance with the Company's fixed charge coverage ratio financial covenant as of the quarter ended June 30, 2023. Although our lenders waived such non-compliance, as discussed below, if sustained, decreased natural gas prices could cause non-compliance with the Company's other financial covenants in subsequent quarters. Non-compliance with financial debt covenants will limit the Company's ability to draw on its existing credit facilities and could also result in our debt agreements being called early, which would move certain noncurrent financial obligations to current. As a result, the Company would have insufficient liquidity and capital resources to be able to repay those obligations. Additionally, the Company's reduced cash flow from operations could cause the Company not to meet its current and noncurrent financial obligations based on our current forecasts. Banpu agreed to provide funding to allow the Company to meet its financial obligations until June 30, 2025, if necessary. On June 16, 2023, the lenders under the Term Loan Credit Agreement and the Revolving Credit Agreement agreed to: (i) waive compliance with our minimum consolidated fixed charge coverage ratio covenant for the quarter ending June 30, 2023; (ii) reduce the ratio required by our minimum consolidated fixed charge coverage ratio covenant to 1.00 to 1.00 for the quarters ending September 30 and December 31, 2023; (iii) waive compliance with our maximum total net leverage ratio covenant for the quarter ending December 31, 2023; and (iv) waive compliance with our required commodity hedging covenant for the quarters ending June 30, September 30 and December 31, 2023. Such waivers did not apply to our obligations in the Term Loan Credit Agreement and the Revolving Credit Agreement to satisfy such financial covenants in order to pay dividends on our common stock and to repay the loan under our BNAC A&R Loan Agreement. Additionally, on July 6, 2023, the lenders under the Revolving Credit Agreement agreed to waive compliance with respect to our minimum marketer receivables covenant for up to $40.0 million of our credit facility borrowings under the Revolving Credit Agreement with total borrowings not to exceed $100.0 million; this waiver was effective through the fiscal quarter ending December 31, 2023 and, on December 26, 2023, the lenders agreed to extend the effectiveness of this waiver until July 31, 2024. On September 29, 2023, we entered into the Fourth Amendment to the Term Loan Credit Agreement and the Fourth Amendment to the Revolving Credit Agreement with the respective lenders thereunder, pursuant to which such credit agreements were amended to (i) remove the Company's maximum total net leverage ratio covenant and minimum consolidated fixed charge coverage ratio covenant; and (ii) insert the following financial covenants: (a) minimum debt service coverage ratio, which could not be less than 1.05 to 1.00 at the end of each fiscal quarter and (b) maximum net indebtedness to equity ratio, which could not be greater than 1.50 to 1.00 at the end of each fiscal quarter.

The Fourth Amendment to the Term Loan Credit Agreement inserted an additional financial covenant that required us to hold a certain amount of cash in our Debt Service Reserve Account. To fund the Debt Service Reserve Account, BKV made a capital call on BNAC of $150.0 million and, pursuant to the requirements of the existing stockholders' agreement, on September 27, 2023, BNAC made such capital contribution in exchange for 7,500,000 shares of BKV common stock (taking into account the October 2023 one-for-two reverse stock split). $138.3 million of BNAC's capital contribution was placed in the Debt Service Reserve Account to comply with our financial covenant under the Term Loan Credit Agreement.

On June 11, 2024, the amounts outstanding under the Term Loan Credit Agreement, the Revolving Credit Agreement and the SCB Credit Facility were paid off with proceeds from the loans under the RBL Credit Agreement and cash on hand. The Term Loan Credit Agreement, the Revolving Credit Agreement and the SCB Credit Facility were terminated concurrently with the repayment of the remaining amounts owed thereunder.

There can be no assurance that, if needed to avoid noncompliance with our debt agreements in the future, we will obtain the necessary waivers from the applicable lenders on satisfactory terms or at all. As a result, there could be an event of default under such agreements, which could result in an acceleration of repayment.

Our borrowings under the BNAC A&R Loan Agreement and RBL Credit Agreement expose us to interest rate risk.

Our results of operations are exposed to interest rate risk associated with borrowings under the BNAC A&R Loan Agreement and the RBL Credit Agreement, which bear interest at rates based on the Secured Overnight Financing Rate ("SOFR") or an alternative floating interest rate benchmark ("ABR"). Interest rates rose significantly during 2022 and remained elevated throughout 2023 and the first half of 2024 as the U.S. Federal Reserve sought to control inflation. Interest rates are currently expected to remain high during 2024. Raising or lowering of interest rates by the U.S. Federal Reserve generally causes an increase or decrease, respectively, in SOFR and other floating interest rate benchmarks. As such, if interest rates increase, so will our interest costs. If interest rates increase in the future, or such interest rates do not decrease over the next few years, it may have a material adverse effect on our results of operations and financial condition.

Our hedging activities do not provide downside protection for all of our production and could result in financial losses or could reduce our net income. Further, our derivative contracts contain certain restrictions and covenants.

From time to time, we enter into derivatives contracts in connection with our natural gas and NGLs, including, for instance, swaps, producer collars and enhanced three-way collars. These derivative arrangements are subject to mark-to-market accounting treatment, and the changes in fair market value of our derivative contracts are reported in our statement of operations and comprehensive loss each quarter, which may result in significant non-cash gains or losses. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments.

These derivative arrangements are designed to reduce our exposure to commodity price decreases. Therefore, to the extent our production is not hedged, we are exposed to declines in commodity prices. In addition, our derivative arrangements may be inadequate to protect us from continuing and prolonged declines in commodity prices. Further, while designed to reduce our exposure to commodity price decreases, these derivatives arrangements may also limit the potential gains we might otherwise receive from increases in commodity prices if such prices rise over the price established by our derivative contracts. For example, for the six months ended June 30, 2024 and 2023, we had realized gains of $67.9 million and $70.7 million, respectively, of which $13.3 million of the $67.9 million, and $39.1 million of the $70.7 million of gains related to early termination of hedges. For the year ended December 31, 2023, we had realized gains of $90.2 million, of which $46.7 million related to early terminations of hedges. These gains are attributable to decreases in underlying commodity prices and volatility in energy markets. However, for the years ended December 31, 2022 and 2021, we incurred realized losses on derivatives of $688.5 million and $268.7 million, respectively, $158.4 million and $30.9 million of which related to early termination of hedges, respectively. For the six months ended June 30, 2024 and 2023, we incurred unrealized losses on derivatives of $79.1 million and unrealized gains on derivatives of $46.2 million, respectively. For the years ended December 31, 2023, 2022 and 2021, we incurred unrealized gains on derivatives of $148.6 million and $58.8 million, and unrealized losses on derivatives of $115.2 million, respectively. In trying to manage our exposure to commodity price risk, we may end up with too many or too few derivative contracts, depending upon where commodity prices settle relative to our derivative price thresholds and how our natural gas and NGL volumes fluctuate relative to our expectations when the derivatives were established.

As of June 30, 2024, we have hedged 297,500 MMBtu/d for the remainder of 2024 and 166,250 MMBtu/d and 23,750 MMBtu/d for 2025 and 2026, respectively, and sold 100,000 MMBtu/d of call options with a strike price of $5.00/MMBtu for 2026 and 2027. In addition, as of June 30, 2024, we have hedged 21,350 Bbl/d for the remainder of 2024 and 10,275 Bbl/d, and 750 Bbl/d of NGLs for 2025 and 2026, respectively. Our results of operations, liquidity and financial condition would be negatively impacted if prices of natural gas and NGLs were to become depressed or decline materially from current levels, or there is otherwise an unexpected material impact on commodity prices, and we have experienced variances in our results of operations and financial condition due to our hedging transactions.

Our hedging activities do not provide downside protection for all of our production. In addition, our ability to use hedging transactions to protect us from future commodity price declines will be dependent upon commodity prices at the time we enter into future hedging transactions and our future levels of hedging and, as a result, our future net cash flows may be more sensitive to commodity price changes. Further, if commodity prices decline materially, we will not be able to replace our hedges or enter into new hedges at favorable prices.

Further, our derivative contracts contain certain restrictions and covenants customary for such types of instruments. For example, an ISDA Master Agreement for certain of our derivative contracts (the "Master Agreement") previously contained a covenant that restricted us from creating, issuing, incurring or assuming additional indebtedness in excess of $75.0 million. In June 2022, in connection with the completion of the Exxon Barnett Acquisition, we borrowed $570.0 million of term loans under the Term Loan Credit Agreement. In connection with exceeding the $75.0 million indebtedness threshold, on August 4, 2022, we executed an amendment to the Master Agreement pursuant to which we were required to novate or terminate, at our election, at least $100.0 million in derivative contracts by October 4, 2022. On September 9, 2022, we terminated derivative contracts of $100.2 million with the counterparty to satisfy this requirement. In connection with such termination, we were required to make cash payments to the counterparty in an aggregate amount of $100.2 million, all of which was paid by November 30, 2022. The Master Agreement, as amended to date, includes a cross-default provision pursuant to which a default by us of the covenants under our Term Loan Credit Agreement would cause a default under the Master Agreement. See "*Note 15 — Credit and Other Risk*" to our audited consolidated financial statements included elsewhere in this prospectus for additional information regarding the Master Agreement.

Subject to restrictions in the RBL Credit Agreement, our hedging strategy and future hedging transactions will be determined at our discretion and may be different than what we have done on a historical basis. In the future, we may enter into additional derivative arrangements or reduce our derivative arrangements. The prices at which we hedge our production in the future will be dependent upon commodities prices at the time we enter into these transactions, which may be substantially higher or lower than current prices. Accordingly, our price hedging strategy may not protect us from significant declines in prices received for our future production. Conversely, our hedging strategy may limit our ability to realize cash flows from future commodity price increases. It is also possible that a substantially larger percentage of our future production will not be hedged, as compared with the next few years, which would result in our natural gas and NGL revenues becoming more sensitive to commodity price fluctuations.

Our hedging transactions could expose us to counterparty credit risk.

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. The risk of counterparty nonperformance is of particular concern in the event of disruptions in the financial markets or the significant decline in commodity prices, which could lead to sudden changes in a counterparty's liquidity and impair their ability to perform under the terms of the derivative contract. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions. Furthermore, the bankruptcy of one or more of our hedge providers or some other similar proceeding or liquidity constraint might make it unlikely that we would be able to collect all or a significant portion of amounts owed to us by the distressed entity or entities.

During periods of falling commodity prices, our hedge receivable positions increase, which increases our exposure. If the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss.

We may experience difficulty in achieving and managing future growth.

Future growth may place strains on our resources and cause us to rely more on project partners and independent contractors, possibly negatively affecting our financial condition, results of operations and cash flows. Our ability to grow will depend on a number of factors, including:

- our ability to acquire additional assets and to successfully integrate acquisitions we may make;
- the results of our drilling program;
- commodity prices;
- our ability to develop existing prospects;
- our ability to obtain leases or options on properties for which we have seismic data;
- our ability to acquire additional seismic data;
- our ability to identify and acquire new exploratory prospects;
- our ability to continue to retain and attract skilled personnel;
- our ability to maintain or enter into new relationships with project partners and independent contractors; and
- our access to capital.

We are a holding company with no operations of our own, and we depend on our subsidiaries and our joint venture for cash to fund all of our operations, taxes and other expenses and any dividends that we may pay.

Our operations are conducted entirely through our subsidiaries, the BKV-BPP Power Joint Venture and the BKV-BPP Cotton Cove Joint Venture. Our ability to generate cash to meet our debt and other obligations, to cover all applicable taxes payable and to declare and pay any dividends on our common stock is dependent on the earnings and the receipt of funds through distributions from our subsidiaries and joint ventures. Our subsidiaries' and joint ventures' respective abilities to generate adequate cash depends on a number of factors, including development of reserves, successful acquisitions of complementary properties, advantageous drilling conditions, natural gas, NGL and oil prices, successful production and sales of electricity, compliance with all applicable laws and regulations and other factors.

Our business is subject to operating hazards that could result in substantial losses or liabilities for which we may not have adequate insurance coverage.

Natural gas and NGLs operations are subject to many risks, including well blowouts, craterings, explosions, uncontrollable flows of natural gas, NGLs or well fluids, fires, pipe, casing or cement failures, abnormal pressure, pipeline leaks, ruptures or spills, vandalism, pollution, releases of toxic gases, adverse weather conditions or natural disasters and other environmental hazards and risks. If any of these hazards occur, we could sustain substantial losses as a result of:

- injury or loss of life;
- severe damage to or destruction of property, natural resources and equipment;
- pollution or other environmental damage;
- investigatory, monitoring, and cleanup responsibilities;
- regulatory investigations and penalties or lawsuits;
- loss of, or delay in revenue;
- suspension or impairment of operations; and
- repairs to resume operations.

We maintain insurance against some, but not all, potential losses or liabilities arising from our operations in accordance with what we believe are customary industry practices and in amounts and at costs that we believe to be prudent and commercially practicable. Our insurance includes deductibles that must be met prior to recovery, as well as sub-limits and/or self-insurance. Additionally, our insurance is subject to exclusions and limitations. Our insurance does not cover every potential risk associated with our operations, including the potential loss of significant revenues. We can provide no assurance that our coverage will adequately protect us against liability from all potential consequences, damages and losses.

We currently have insurance policies covering our operations that include coverage for general liability, property damage to certain of our real and personal property, and certain personal property of others, excess liability, physical damage to our upstream and natural gas midstream properties, operational control of wells, redrilling expenses, pollution and cleanup, site pollution incidents, damage to lease property, business and contingent business interruption, management liability, automobile liability, third-party liability, workers' compensation, employer's liability, kidnap and ransom and other coverages. Our insurance policies provide coverage for losses or liabilities relating to pollution, but are largely limited to coverage for sudden and accidental occurrences. For example, the site pollution incident policy we maintain includes coverage for obligations, expenses or claims that we may incur from a sudden incident that results in negative environmental effects, including obligations, expenses or claims related to seepage and pollution, cleanup and containment, evacuation expenses and control of the well (subject to policy terms and conditions). In the specific event of a well blowout or out-of-control well resulting in negative environmental effects, such operator's extra expense coverage would be our primary source of coverage, with the general liability and excess liability coverage referenced above also providing certain coverage.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. Some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable, and we may elect to maintain minimal or no insurance coverage. If we incur substantial liability from a significant event and the damages are not covered by insurance or are in excess of policy limits, then we would have lower revenues and funds available to us for our operations, that could, in turn, have a material adverse effect on our business, financial condition and results of operations.

Additionally, we rely to a large extent on transportation owned and operated by third parties and damage to, or destruction of, those third-party facilities could affect our ability to process, transport and sell our production. To a limited extent, we maintain business interruption insurance related to our processing plants where we are insured for potential losses from the interruption of production caused by loss of or damage to the processing plant.

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

There is intense competition for acquisition opportunities in our industry and we may not be able to identify attractive acquisition opportunities. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms. We may not be able to obtain contractual indemnities from sellers for liabilities incurred prior to our purchase of the business, asset or property. No assurance can be given that we will be able to identify additional suitable acquisition or asset exchange opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. In addition, there can be no assurance that Banpu will not engage in competition with us in the future. See "*— Risks Related to Our Relationship with Banpu and its Affiliates — Banpu's interests, including interests in certain corporate opportunities, may conflict with our interests and the interests of our other stockholders. Conflicts of interest between us and Banpu could be resolved in a manner unfavorable to us and our other stockholders.*" Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions.

We may make acquisitions of properties or businesses that complement or expand our current business in the future. The successful acquisition of natural gas and NGL properties requires an assessment of several factors, including:

- recoverable reserves;
- future commodity prices;
- operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain and rely on numerous assumptions and we may not be able to identify accretive acquisition opportunities. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Reviews may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when a review is performed. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. Market forces often prevent us from negotiating contractual indemnification for environmental liabilities and require us to acquire properties on an "as is" basis.

The success of any of our acquisitions will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources which may divert management's attention from other business concerns. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully, or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition, results of operations and cash flows.

In addition, the BNAC A&R Loan Agreement and the RBL Credit Agreement (and, in respect of the RBL Credit Agreement, solely with respect to the RBL Borrower and its restricted subsidiaries) prohibit us from entering into mergers or combination transactions. These debt arrangements also limit our ability to incur indebtedness and liens, which could indirectly limit our ability to engage in acquisitions.

Our business requires substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms or be able to fund our working capital needs from cash flow from operations, which could lead to a decline in our reserves.

The energy industry is capital intensive. We have made and expect to continue to make substantial capital expenditures in our businesses for the acquisition, exploration, production and development of natural gas and NGL reserves, as well as the gathering, processing and transportation of natural gas and NGLs and the development of our CCUS business. Our capital expenditures in 2021 totaled $63.9 million, primarily relating to completion of drilled but uncompleted wells prior to January 1, 2021, projects to increase reserves recovery and investment in non-operated wells. Our capital expenditures in 2022 totaled $235.4 million, primarily relating to completion of drilled but uncompleted wells prior to January 1, 2022, investment in operated wells, projects to increase reserves recovery, and investment in non-operated wells. Our capital expenditures in 2023 totaled $165.9 million, primarily relating to the completion of drilled but uncompleted wells prior to January 1, 2023, our investment in our CCUS business, and projects to increase reserves recovery.

The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, commodity prices, actual drilling results, the availability of drilling rigs and other services and equipment, the availability of CO_2 transportation pipelines in proposed CCUS project areas, and legal, regulatory, environmental, technological and competitive developments. Natural gas prices decreased significantly during 2023 and are projected to remain lower than the near-record high prices experienced in 2022. In response to this natural gas pricing environment, we have decreased our capital expenditures budget for the development of natural gas properties for 2024 from approximately $73.0 million to approximately $13.0 million. A sustained decline in commodity prices may result in further decreases in our actual capital expenditures, which would negatively impact our ability to grow production. Although we intend to finance our future capital expenditures primarily through cash flow from operations and through available capacity under the RBL Credit Agreement, our future needs may require us to alter or increase our capitalization substantially through the increase in the size of our working capital facilities, issuance of additional debt or equity securities or the sale of assets.

Our cash flow from operations and access to capital are subject to a number of variables, including:

- the estimated quantities of our natural gas and NGL reserves;
- the amount of hydrocarbon we produce from existing wells;
- the prices at which we sell our production;
- the levels of our operating expenses;
- take-away and storage capacity;
- our ability to acquire, locate, develop and produce new reserves; and
- our ability to borrow under the RBL Credit Agreement and any additional working capital facilities that we obtain.

If our revenues decrease as a result of lower commodity prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our planned capital budget or operations at current levels. For example, the recent decline in commodity prices may reduce the amount of capital the Company can raise through debt or equity financing. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If cash flow generated by our operations or available capacity under the RBL Credit Agreement is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our properties or our CCUS business, which in turn could lead to a decline in our reserves and production and a failure to meet our net zero goals, and could adversely affect our business, financial condition and results of operations.

We may be unable to dispose of nonstrategic assets on attractive terms and may be required to retain liabilities for certain matters.

We regularly review our asset base to assess the market value versus holding value of existing assets with a view to optimizing deployed capital. Our ability to dispose of nonstrategic assets or complete dispositions, such as acreage that we do not intend to place on our production schedule prior to lease expirations, could be affected by various factors, including the availability of buyers willing to purchase the nonstrategic assets at prices acceptable to us. Sellers typically retain certain liabilities or agree to indemnify buyers for certain matters. The magnitude of any such retained liability or indemnification obligation may be difficult to quantify at the time of the transaction and ultimately may be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release us from guarantees or other credit support provided prior to the sale of the divested assets.

As a result, after a sale, we may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

We may be unable to compete effectively with larger companies, which may adversely affect our ability to generate sufficient revenues.

The energy industry is intensely competitive, and we compete with other companies that have greater resources than we do. Our ability to acquire additional properties, to discover reserves in the future and to execute on potential CCUS projects will be dependent upon our ability to evaluate and select suitable properties to consummate transactions in a highly competitive market. Many of our larger competitors not only drill for and produce natural gas, NGLs and oil, but they also engage in refining operations and market petroleum and other products on a regional, national or worldwide basis. Our competitors may be able to pay more for natural gas and NGL properties, evaluate, bid for and purchase a greater number of properties than our financial or human resources permit and attract capital at lower rates. In addition, these companies may have a greater ability to continue drilling, production and workover activities during periods of low natural gas and NGL prices, to contract for drilling, production and workover equipment, to pay more for and secure trained personnel, and to absorb the burden of present and future federal, state, local and other laws and regulations. The natural gas, NGL and oil industry has periodically experienced shortages of drilling rigs, equipment, hydraulic fracturing fleets, supply chain resources, pipelines and personnel, which has delayed development drilling and other exploitation activities and has caused significant price increases. Competition has been strong in hiring experienced personnel, particularly in the engineering and technical, accounting and financial reporting, tax and land departments. In addition, competition is strong for attractive natural gas, NGL and oil producing properties, natural gas, NGL and oil companies, undeveloped leases and drilling rights, and CCUS projects. Further, the current inflation may affect us more than it may affect some of our larger competitors. Our inability to compete effectively with our competitors could have a material adverse impact on our business activities, financial condition and results of operations.

The energy industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage or competitive pressures may force us to implement those new technologies at substantial costs. Further, competitors may obtain patents which might prevent us from implementing new technologies. In addition, other energy companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete or if we are unable to use the most advanced commercially available technology, our business, financial condition and results of operations could be materially adversely affected.

The inability of one or more of our significant counterparties to meet their payment or performance obligations may adversely affect our financial results.

We are subject to certain credit risks associated with nonpayment or nonperformance by our counterparties, including joint interest partners and customers. Joint interest receivables arise from billing our joint interest partners who own a partial working interest in our natural gas and NGL wells. These entities participate in our natural gas and NGL wells primarily based on their ownership in leases on which we operate, and we have limited ability to control their participation in our natural gas and NGL wells. Sales receivables arise from the sale of our natural gas and NGL production to our customers. We currently market, directly or indirectly, our natural gas and NGL production to energy marketing companies, refineries, gas processors, petrochemical companies, local distribution companies, power plants and other end users.

We maintain credit procedures and policies to mitigate the credit risks posed by our counterparties. However, our credit procedures and policies may not be adequate to fully eliminate the risk and we do not require all of our counterparties to post collateral. If we fail to adequately assess the creditworthiness of our existing or future significant counterparties, or their creditworthiness unexpectedly materially deteriorates, any resulting nonpayment or nonperformance by them could have a materially adverse effect on our financial condition and results of operations.

Our business could be negatively affected by security threats and disruptions, including electronic, cybersecurity or physical security threats and other disruptions.

Our businesses face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. The potential for such security threats has subjected our operations to increased risks that could have a material adverse effect on our business. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. Security breaches could lead to losses of sensitive information, critical infrastructure or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations and cash flows. In addition, to assist in conducting our business, we rely on information technology systems and data hosting facilities, including systems and facilities that are hosted by third parties and with respect to which we have limited visibility and control. These systems and facilities may be vulnerable to a variety of evolving cyber security risks or information security breaches, including unauthorized access, denial-of-service attacks, malicious software, data privacy breaches by employees, insiders or others with authorized access, cyber or phishing-attacks, ransomware, malware, social engineering, physical breaches or other actions. The use by BKV and its third-party service providers to a hybrid systems model including on-premises and cloud environments has transformed how systems interconnect, how data is stored, how users interact with applications and what end user devices are utilized. This hybrid systems model has resulted in additional cybersecurity risk, and cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to data and systems and other electronic security breaches that could lead to disruptions in critical systems, including third-party systems that we do not control. These events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability.

We may face various risks associated with the long-term trend toward increased activism against natural gas, NGL and oil exploration and development activities.

Opposition toward natural gas, NGL and oil drilling and development activity has been growing globally. Companies in the natural gas, NGL and oil industry are often the target of activist efforts from both individuals and non-governmental organizations regarding safety, environmental compliance and business practices. Anti-development activists are working to, among other things, reduce access to federal and state government lands and delay or cancel certain projects such as the development of natural gas, NGL and oil shale plays. For example, environmental activists continue to advocate for increased regulations or bans on shale drilling and hydraulic fracturing in the United States, even in jurisdictions that are among the most stringent in their regulation of the industry. Future activist efforts could result in the following:

- delay or denial of drilling permits;
- shortening of lease terms and reduction in lease size;
- restrictions on installation or operation of production, gathering or processing facilities;

- restrictions on the use of certain operating practices, such as hydraulic fracturing, or disposal of related waste materials, such as hydraulic fracking fluids and production;
- increased severance and/or other taxes;
- cyber-attacks;
- legal challenges or lawsuits;
- negative publicity about our business or the natural gas, NGL and oil industry in general;
- increased costs of doing business;
- reduction in demand for our products; and
- other adverse effects on our ability to develop our properties and expand production.

Similarly, some activists view CCUS as a means to either promote the fossil fuel industry or avoid transition to other sources of energy, and thus, are often opposed to such projects regardless of any potential environmental benefits. We may need to incur significant costs associated with responding to these or other initiatives, and there is no guarantee that our responses will produce favorable outcomes or results. Complying with any resulting additional legal or regulatory requirements that are substantial could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Prolonged negative investor sentiment toward upstream natural gas, NGL and oil focused companies could limit our access to capital funding, which would constrain liquidity.

Certain segments of the investor community have developed negative sentiment towards investing in our industry. Recent equity returns in the sector versus other sectors have led to lower natural gas, NGL and oil representation in certain key equity market indices. Some investors, including certain pension funds, university endowments and family foundations, have stated policies to reduce or eliminate their investments in the natural gas, NGL and oil sector based on social and environmental considerations. Certain other stakeholders have pressured commercial and investment banks to stop funding natural gas, NGL and oil projects. If this negative sentiment continues for a prolonged period of time, it may reduce the availability of capital funding for potential development projects, each of which could have a material adverse effect our financial condition, results of operations and cash flows.

We may be involved in legal proceedings that could result in substantial liabilities.

Like many energy companies, in the ordinary course of our business, we are from time to time involved in various disputes and disagreements that may lead to legal and other proceedings, such as title, royalty or contractual disputes, regulatory compliance matters and personal injury or property damage matters. Such legal proceedings are inherently uncertain and their results cannot be predicted. Regardless of the outcome, such proceedings could have an adverse impact on us because of legal costs, diversion of management and other personnel and other factors. In addition, it is possible that a resolution of one or more such proceedings could result in liability, penalties or sanctions, as well as judgments, consent decrees or orders requiring a change in our business practices, which could materially and adversely affect our business, prospects, financial condition, results of operations and cash flows. Accruals for such liability, penalties or sanctions may be insufficient, and judgments and estimates to determine accruals or range of losses related to legal and other proceedings could materially change from one period to the next.

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 such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure, possible consequences include our loss of communication links, inability to find, produce, process and sell natural gas and NGLs and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business.

We are highly dependent on our executive officers and technical personnel, the loss of any of whom could adversely affect our operations. Additionally, the continued success of our business depends on our ability to attract and retain experienced technical personnel.

We depend on the services of our senior management and technical personnel. There can be no assurance that we would be able to replace such members of management with comparable replacements or that such replacements would integrate well with our existing team. Further, the loss of the services of our senior management could have a material adverse effect on our business, financial condition and results of operations. We do not maintain, nor do we plan to obtain, any "key-man" life insurance against the loss of any of these individuals. As a result, we are not insured against any losses resulting from the death of our key employees. The loss of the services of our senior management or technical personnel could have a material adverse effect on our business, prospects, financial condition, results of operations and cash flows.

Our continued success will depend, in part, on our ability to attract and retain experienced technical personnel, including geologists, engineers and other professionals. Competition for these professionals is strong and will likely intensify as a significant portion of today's engineers, geologists and other professionals working within the oil and natural gas industry will reach the age of retirement in the coming years. Acquiring and retaining these personnel could prove more difficult or cost substantially more than estimated.

In addition, Christopher Kalnin serves as a member of Banpu's Executive Committee with responsibilities to Banpu to, among other things, manage all aspects of Banpu's business in North America. Although our corporate opportunity policy requires Mr. Kalnin to present applicable business opportunities sourced by him to our company before such opportunities may be presented to Banpu, Banpu or its affiliates may compete with us for acquisition or other business opportunities. Our independent directors also serve, or may in the future serve, as officers and board members for other entities. If our officers' and directors' other business affairs require them to devote substantial amounts of time to such affairs, it could limit their ability to devote time to our affairs which may have a negative impact on our ability to compete or follow the elements of our business strategy. For additional information about limitations on our access to business opportunities sourced by our officers or directors, see "*Management — Conflicts of Interest*."

For as long as we are an emerging growth company, we will not be required to comply with certain reporting requirements, including disclosure about our executive compensation, that apply to other public companies.

We are classified as an "emerging growth company" under the JOBS Act. In addition, we have reduced Sarbanes-Oxley Act compliance requirements, as discussed elsewhere, for as long as we are an emerging growth company, which may be up to five full fiscal years. Unlike other public companies, we will not be required to, among other things, (i) comply with any new requirements adopted by the PCAOB requiring mandatory audit firm rotation or a supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer, (ii) provide certain disclosure regarding executive compensation required of larger public companies or (iii) hold nonbinding advisory votes on executive compensation.

To the extent that we rely on any of the exemptions available to emerging growth companies, you will receive less information about our executive compensation and internal control over financial reporting than issuers that are not emerging growth companies. If some investors find our common stock to be less attractive as a result, there may be a less active trading market for our common stock and our stock price may be more volatile.

Risks Related to Environmental, Legal Compliance and Regulatory Matters

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations.

Our natural gas and NGL exploration and production operations are subject to complex and stringent laws and regulations. To conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. Failure or delay in obtaining regulatory approvals or drilling and related permits could have a material adverse effect on our ability to develop our properties, and receipt of drilling and related permits with onerous conditions could increase our compliance costs or decrease our opportunities to execute projects and develop acreage. In addition, regulations regarding conservation practices and the protection of correlative rights affect our operations by limiting the quantity of natural gas and NGLs we may produce and sell.

We are subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration, production and transportation of natural gas and NGLs. The possibility exists that new laws, regulations or enforcement policies could be more stringent and significantly increase our compliance costs or cause us to cease operations. If we are not able to recover the resulting costs through insurance or increased revenues and our financial condition could be adversely affected.

Increased attention to ESG matters and environmental conservation measures may adversely impact our business.

Increasing attention to climate change, societal expectations on companies to address climate change, investor and societal expectations regarding voluntary ESG initiatives and disclosures and consumer demand for alternative forms of energy may result in increased costs (including, but not limited to, increased costs related to compliance, stakeholder engagement, contracting and insurance), reduced demand for our products, reduced profits, increased investigations and litigation and negative impacts on our access to capital markets. Increasing attention to climate change, environmental justice and environmental conservation, for example, may result in demand shifts for natural gas, NGL and oil products and additional governmental investigations and private litigation against us. To the extent that societal pressures or political or other factors are involved, it is possible that such liability could be imposed without regard to our causation of or contribution to the asserted damage, or to other mitigating factors.

Moreover, while we may create and publish voluntary disclosures regarding ESG matters from time to time, many of the statements in those voluntary disclosures are based on hypothetical expectations and assumptions that may or may not be representative of current or actual risks or events or forecasts of expected risks or events, including the costs associated therewith. Such expectations and assumptions are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying, measuring and reporting on many ESG matters. Such disclosures may also be at least partially reliant on third-party information that we have not verified, or cannot verify, independently. In addition, we expect there will likely be increasing levels of regulation, disclosure-related and otherwise, with respect to ESG matters, and increased regulation will likely lead to increased compliance costs as well as scrutiny that could heighten all of the risks identified in this risk factor. We may also take certain actions to improve the ESG profile of our Company and/or products, but we cannot guarantee that such actions will have the desired effect.

In addition, we note that standards and expectations regarding carbon accounting and the processes for measuring and counting GHG emissions and various environmental attributes (including but not limited to offsets and renewable energy credits) are evolving, and it is possible that our approach to measuring both our emissions (and any corresponding reductions) and our approaches to reducing emissions may be, either currently by some stakeholders or at some future point, considered inconsistent with common or best practices including as such practice is interpreted by individual stakeholders and their own expectations, with respect to measuring and accounting for such matters, reducing overall emissions, effectively sequestering emissions, maintaining a “closed loop” approach to emissions and/or achieving “net zero,” whether for our entire emissions inventory, a particular business segment or for particular products. If our approaches to such matters fall out of step with particular stakeholder expectations, we may be subject to additional scrutiny, criticism, regulatory and investor or litigation, any of which may adversely impact our business, financial condition or results of operations. For example, there has been increasing scrutiny on and criticism of the certification or labelling of certain fossil fuel products as “responsible” or similar labels, as well as on various marketing or other claims related to the use of offsets or the emission profile of products, given alleged deficiencies in the monitoring processes used to support such certifications or claims, which may adversely impact demand for, and any premium associated with, such certifications and claims. Our plans and claims regarding our “Pad of the Future” program and RSG and our intent to produce Carbon Sequestered Gas may come under criticism, expose us to potential litigation or otherwise impact our reputation and financial performance. For example, our plan to retire carbon credits against our Scope 1 and Scope 3 emissions instead of transferring such credits with our produced natural gas may impact certain customers' willingness or ability to use Carbon Sequestered Gas to meet their own emissions goals, and thus adversely impact demand for such product. Additionally, disputes or ambiguities regarding the methodologies used to certify and register carbon credits associated with CCUS projects could delay or prevent our efforts to certify and register the environmental attributes associated with our CCUS projects as tradeable carbon credits, including the development of a blockchain ledger and tokens to facilitate the transfer of environmental attributes, which may negatively impact our net zero strategy, including by delaying or preventing our achievement of net zero. Such failure may also otherwise impact our operations to the extent such certification or similar condition is required, such as with our contracts with ENGIE and Kiewit. In some instances, relevant information or timing for our emissions reduction and other ESG efforts is dependent on third parties, who may not act in a manner or timeline that aligns with our expectations or desires. Similarly, even if we successfully achieve any or all of our net zero goals, as described herein, we may not see a benefit from such efforts to the extent other stakeholders disagree with, among other things, the structure of such goal or the methodology, accounting or data sources associated therewith.

Additionally, various regulators have adopted, or are considering adopting, regulations on environmental marketing claims, including but not limited to the use of climate-related language such as "net zero" in product marketing. These requirements may use different criteria or methodologies than we currently use in assessing our net zero strategy or products, such as our intentions to develop Carbon Sequestered Gas. Any new regulations adopted, or existing regulations subject to new interpretations, may require us to change our internal assessment criteria, restrict our use of certain marketing claims or our ability to benefit from initiatives we have undertaken or otherwise adversely impact our operations.

Increasing attention to global climate change has resulted in increased investor attention and an increased risk of public and private litigation, which could increase our costs or otherwise adversely affect our business. A number of parties have sought to bring suit against the largest oil and gas companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing, handling or marketing fuels that contributed to global warming effects, such as rising sea levels, and therefore are responsible for roadway and infrastructure damages, or alleging that the companies have been aware of the adverse effects of climate change for some time but failed to adequately disclose those impacts. The ultimate outcome and impact to us of any such litigation cannot be predicted with certainty, and we could incur substantial legal costs associated with defending these and similar lawsuits in the future.

In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to inform their investment and voting decisions. Unfavorable ESG ratings and recent activism directed at shifting funding away from companies with energy-related assets could lead to increased negative investor sentiment toward us and our industry and to the diversion of investment to other industries, which could have a negative impact on our access to and costs of capital. Stockholder activism has also recently been increasing in our industry, and stockholders may attempt to effect changes to our business or governance, whether by stockholder proposals, public campaigns, proxy solicitations or otherwise. Any of these risks could result in unexpected costs, negative sentiments about us, disruptions in our operations, increases to our operating expenses and reduced demand for our products, which in turn could have an adverse effect on our business, financial condition and results of operations.

There are also increasing financial risks for fossil fuel producers as stockholders currently invested in fossil-fuel energy companies may elect in the future to shift some or all of their investments into other sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies, which could result in the restriction, delay or cancellation of drilling programs or development or production activities and affect our access to capital for potential growth projects. For example, at COP26, the Glasgow Financial Alliance for Net Zero ("GFANZ") announced that commitments from over 450 firms across 45 countries had resulted in over $130 trillion in capital committed to net zero goals. The various sub-alliances of GFANZ generally require participants to set short-term, sector-specific targets to transition their financing, investing, and/or underwriting activities to net zero emissions by 2050. There is also a risk that financial institutions will be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. In 2021, President Biden signed an executive order calling for the development of a “climate finance plan” and, separately, in 2020, the Federal Reserve joined the Network for Greening the Financial System (“NGFS”), a consortium of financial regulators focused on addressing climate-related risks in the financial sector. In November 2021, the Federal Reserve issued a statement in support of the efforts of the NGFS to identify key issues and potential solutions for the climate-related challenges most relevant to central banks and supervisory authorities.

Moreover, to the extent ESG matters negatively impact our reputation, we may not be able to compete as effectively to recruit or retain employees. Such ESG matters may also impact our suppliers or customers, which may adversely impact our business, financial condition or results of operations.

Energy conservation measures and technological advances could reduce demand for natural gas, NGL and oil.

Energy conservation measures, alternative fuel requirements, governmental requirements for renewable energy resources, increasing consumer demand for alternatives to natural gas, NGL and oil, technological advances in fuel economy and energy generation devices could reduce demand for natural gas, NGLs and oil. The impact of the changing demand for natural gas, NGL and oil services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Significant physical effects of climatic change have the potential to damage our facilities, disrupt our production activities and cause us to incur significant costs in preparing for or responding to those effects.

Climate change could have an effect on the severity of weather (including hurricanes, droughts and floods), sea levels, the arability of farmland, changes in temperature and other meteorological patterns and water availability and quality. If such effects were to occur, our development and production operations have the potential to be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low lying areas, disruption of our production activities either because of climate-related damages to our facilities or in our costs of operation potentially arising from such climatic effects, less efficient or non-routine operating practices necessitated by climate effects or increased costs for insurance coverage in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change. We have developed and started to implement a plan to address the potential impacts of climate change on our operations, but we cannot assure you that our operations will not be negatively impacted by climate change.

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

Hydraulic fracturing is used in many of our operations to stimulate production of hydrocarbons, particularly natural gas and NGLs. The process involves the injection of water, sand and additives under pressure into a targeted subsurface formation to fracture the surrounding rock and stimulate production. The U.S. Congress (“Congress”) from time to time has considered legislation to amend the federal Safe Drinking Water Act (“SDWA”) to remove the exemption currently available to hydraulic fracturing, which would place additional regulatory burdens upon hydraulic fracturing operations, including requirements to obtain a permit prior to commencing operations adhering to certain construction requirements, to establish financial assurance, and to require reporting and disclosure of the chemicals used in those operations. Such legislation has not passed.

Hydraulic fracturing (other than that using diesel) is currently generally exempt from regulation under the SDWA’s UIC program and is typically regulated by state oil and natural gas commissions or similar agencies. However, several federal agencies have asserted regulatory authority or pursued investigations over certain aspects of the process.

For example, in June 2016, the EPA adopted effluent limitations for the treatment and discharge of wastewater resulting from onshore unconventional natural gas, NGL and oil extraction facilities to publicly owned treatment works and, in 2014, the EPA asserted regulatory authority pursuant to the UIC program over hydraulic fracturing activities involving the use of diesel and issued guidance covering such activities.

Also, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources “under some circumstances.” The final report identified the following risks: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. To date, EPA has taken no further action in response to the December 2016 report.

In addition, some states have adopted, and other states are considering adopting, regulations that restrict or could restrict hydraulic fracturing in certain circumstances. Further, state and local governmental entities have exercised the regulatory powers to regulate, curtail or in some cases prohibit hydraulic fracturing. New laws or regulations that impose new obligations on, or significantly restrict hydraulic fracturing, could make it more difficult or costly for us to perform hydraulic fracturing activities and thereby affect our determination of whether a well is commercially viable and increase our cost of doing business. Such increased costs and any delays or curtailments in our production activities could have a material adverse effect on our business, prospects, financial condition, results of operations and liquidity.

Regulatory action may cause us to shut in or curtail production.

Our rate of production and access to transportation and storage options may also be affected by U.S. federal and state regulation of oil and natural gas production. In 2020, actions of foreign oil producers such as Saudi Arabia and Russia and the impact on global demand of the COVID-19 pandemic materially decreased global crude oil prices and generated a surplus of oil. As a result, regulatory action to curtail production has been contemplated in Texas. For example, the TRRC, which regulates the production of oil and natural gas in the State of Texas, held a hearing in April 2020 regarding potential production cuts for producers in Texas in light of the recent decline in oil prices globally. While the TRRC ultimately declined to institute mandatory production cuts, the agency may choose to revisit the issue. Global and domestic oil prices have recovered substantially to the point that TRRC curtailments are highly unlikely. However, if the TRRC decides to limit the production of crude oil in Texas in the future, our business and results of operations are not likely to be materially and adversely impacted given that our production comes from dry gas wells.

Any such production limitations will likely force us to shut in production. If we are forced to shut in production as a result of regulatory actions or otherwise, we will likely incur greater costs to bring the associated production back online. Cost increases necessary to bring the associated wells back online may be significant enough that such wells would become uneconomic at low commodity price levels, which may lead to decreases in our proved reserves estimates and potential impairments and associated charges to our earnings. If we are able to bring wells back online, there is no assurance that such wells will be as productive following recommencement as they were prior to being shut in. Any shut in or curtailment of the natural gas and NGLs produced from our fields could adversely affect our financial condition, results of operations, cash flows and ability to fulfill our obligations under our firm transportation service agreements.

Our operations are subject to a series of risks relating to climate change that could result in increased compliance or operating costs, limit the areas in which we may conduct natural gas and NGL exploration and production activities, and reduce demand for the natural gas and NGLs we produce.

Climate change continues to attract considerable public and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of carbon dioxide, methane and other GHGs. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs and regulations that directly limit GHG emissions from certain sources.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, in August 2022, Congress passed, and President Biden signed into law, the Inflation Reduction Act of 2022, which imposes several new climate-related requirements on oil and gas operations and appropriates significant federal funding for renewable energy initiatives. The Inflation Reduction Act, for the first time ever, imposes a fee on GHG emissions from certain facilities. The emissions fee and funding provisions of the law could increase our operating costs and accelerate the transition away from fossil fuels, which could in turn adversely affect our business and results of operations.

Moreover, following the U.S. Supreme Court finding in 2007 that GHG emissions constitute a pollutant under the CAA, the EPA adopted regulations that, among other things, establish construction and operating permit reviews for GHG emissions from certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, and together with the U.S. Department of Transportation (“DOT”), imposing GHG emissions and fuel economy standards for vehicles in the United States. The regulation of methane from oil and gas facilities has been subject to uncertainty in recent years. The EPA previously had promulgated New Source Performance Standards (“NSPS”) imposing limitations on methane emissions from sources in the oil and gas sector. Subsequently, in September 2020, the Trump Administration rescinded those methane standards and removed the transmission and storage segments from the oil and gas source category under the CAA’s NSPS. However, on June 30, 2021, President Biden signed a resolution passed by Congress under the Congressional Review Act nullifying the September 2020 rule, effectively reinstating the prior standards. In addition, on December 2, 2023, the EPA announced finalized rules establishing requirements for methane emissions from existing and modified oil and gas sources and imposed additional requirements for new sources with respect to methane emissions, including sourcing not previously regulated under the oil and gas source category (the “2023 Methane Rules”). In addition, on May 6, 2024, the EPA released its revised regulations for GHG emissions reporting (“Subpart W Regulations”) that will have an impact on the quantity of GHG emissions reported and the associated payment of fees under the Waste Emissions Charge imposed by the IRA that may be applicable to our operations. In addition, EPA is also proposing additional regulations that will require BKV to report energy consumption data to the US EPA ("Subpart B Regulations"), that will increase the overall regulatory burden for reporting. We continue to review additional changes to rules, such as the revised regulations issued by the Bureau of Land Management to reduce flaring and natural gas waste on federal leases or updates to its onshore oil and gas leasing rules that may impact our current or future operations.

The reinstatement of direct regulation of methane emission for new sources, promulgation of requirements for existing oil and gas sources and enhanced requirements for new sources, and the expansion of sources covered by the EPA’s rules, could result in increased compliance costs or otherwise impact our results of operations.

Various states and groups of states have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as GHG cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. For example, several states, including Pennsylvania and New Mexico, have proposed or adopted regulations restricting the emission of methane from exploration and production activities. At the international level, President Biden has recommitted the United States to the Paris Agreement and, in April 2021, announced a goal of reducing the United States’ economy-wide GHG emissions by 50-52% below 2005 levels by 2030. In November 2021, the international community gathered in Glasgow at the 26th Conference to the Parties on the UN Framework Convention on Climate Change (“COP26”), during which multiple announcements were made, including a call for parties to eliminate certain fossil fuel subsidies and pursue further action on non-CO_2 GHGs. Relatedly, the United States and European Union jointly announced the launch of the “Global Methane Pledge,” which aims to cut global methane pollution at least 30% by 2030 relative to 2020 levels, including “all feasible reductions” in the energy sector. President Biden also agreed in November 2021 to cooperate with Chinese leader Xi Jinping on accelerating the transition to a global net zero economy. The impacts of these pledges, agreements and any legislation or regulation promulgated to fulfill the United States’ commitments under the Paris Agreement, COP26, or other international conventions cannot be predicted at this time. However, to the extent these developments result in new restrictions on natural gas and NGL operations, increase operational costs, or otherwise reduce the demand for natural gas and NGLs, they could have a material adverse effect on our business.

Governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States, including climate change related pledges made by certain candidates now in public office. On January 27, 2021, President Biden issued an executive order that calls for substantial action on climate change, including, among other things, the increased use of zero-emission vehicles by the federal government, the elimination of subsidies provided to the fossil fuel industry, and increased emphasis on climate-related risks across government agencies and economic sectors. The Biden Administration also issued orders temporarily suspending the issuance of authorizations, and suspending the issuance of new leases pending a study, for oil and gas development on federal lands, although such orders are no longer in effect. For more information, see "*Business — Government Regulation and Environmental Matters*." As a result, we cannot predict the full impact of these developments or whether further restrictions may be pursued. Other actions that could be pursued by the Biden Administration may include the imposition of more restrictive requirements for the establishment of pipeline infrastructure or the permitting of LNG export facilities, as well as more restrictive GHG emission limitations for oil and gas facilities. In January 2024, the Biden Administration announced a temporary pause on the Department of Energy's ("DOE") review of pending applications for authorization to export LNG to countries that have not entered into free trade agreements ("FTAs") with the United States (so-called non-FTA countries). The temporary pause was intended to last until DOE could update its underlying analyses for authorizations using more current data to account for considerations like potential energy cost increases for consumers and manufacturers or the latest assessment of the impact of GHGs. However, a number of states have filed a judicial challenge to the temporary pause and on July 1, 2024 a federal district court granted a stay of the DOE pause. We continue to monitor this judicial challenge, but we cannot predict when or whether the temporary pause will resume. The temporary pause is not expected to affect LNG exports that have already been authorized but may have a material impact on the operations of U.S.-based LNG exporters, which could affect demand for natural gas, generally.

Additionally, in March 2024, the SEC finalized a new rule requiring the reporting of climate-related risks and financial impacts, as well as GHG emissions for larger companies. Compliance dates under the final rule are phased in by registrant category. Smaller reporting companies will be required to incorporate climate-related disclosures into their filings beginning in fiscal year 2027. Accelerated filers will be required to incorporate the disclosures in fiscal year 2026, as well as disclosure of Scope 1 and 2 GHG emissions, if material, in fiscal year 2028, and limited assurance attestation reports related to the same by fiscal year 2031. Large accelerated filers will be required to incorporate the disclosures in fiscal year 2025, with Scope 1 and 2 GHG emissions disclosures, if material, in fiscal year 2026, and attestation reports by fiscal year 2029. The new rule is currently being challenged in the U.S. Court of Appeals for the Eighth Circuit and, in April 2024, the SEC voluntary stayed the effective date of the rule. We continue to monitor this judicial challenge and are currently assessing the final rule, but we cannot predict the costs of implementation or any potential adverse impacts resulting from the rule. In addition, other policymakers, including the State of California, have adopted (or are considering adopting) similar or more stringent regulations. Enhanced climate disclosure requirements could accelerate the trend of certain stakeholders and lenders restricting or seeking more stringent conditions with respect to their investments in certain carbon intensive sectors. The adoption and implementation of new or more stringent international, federal or state legislation, regulations or other regulatory initiatives that impose more stringent standards for GHG emissions from the oil and gas sector or otherwise restrict the areas in which this sector may produce oil and gas or generate GHG emissions could result in increased costs of compliance or costs of consuming, and thereby reduce demand for, oil and gas. Additionally, political, litigation and financial risks may result in us restricting or cancelling production activities, incurring liability for infrastructure damages as a result of climatic changes, or having an impaired ability to continue to operate in an economic manner. One or more of these developments could have a material adverse effect on our business, financial condition and results of operations.

Our ability to pursue our business strategies may be adversely affected if we incur costs and liabilities due to a failure to comply with environmental, health and safety laws or regulations or a release into the environment.

We may incur significant costs and liabilities as a result of environmental requirements applicable to the operation of our wells, gathering systems and other facilities. These costs and liabilities could arise under a wide range of federal, state and local environmental, health and safety laws and regulations, including, for example, the following federal laws and their state counterparts, as amended from time to time:

- the CAA, which regulates the emission of air pollutants from many sources, imposes various preconstruction, monitoring and reporting requirements and is relied upon by the EPA as authority for adopting climate change regulatory initiatives relating to GHG emissions;
- the Federal Water Pollution Control Act, also known as the Clean Water Act (“CWA”), which regulates the discharge of pollutants from facilities to state and federal waters and establishes the extent to which waterbodies are subject to federal jurisdiction and rulemaking as protected waters of the United States;
- the SDWA, which is designed to protect the quality of the nation’s public drinking water through adoption of drinking water standards and UIC over the subsurface injection of fluids into belowground formations;
- the federal Resource Conservation and Recovery Act, as amended (“RCRA”), which imposes requirements for the generation, treatment, storage, transport, disposal and cleanup of nonhazardous and hazardous wastes;
- the federal Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA”), which imposes liability on generators, and those who arrange for the transportation, treatment or disposal, of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur as well as on present and certain past owners and operators of those sites;
- the Emergency Planning and Community Right-to-Know Act, which requires facilities to implement a safety hazard communication program and disseminate information to employees, local emergency planning committees and response departments about toxic chemical uses and inventories; and
- the Endangered Species Act (“ESA”), which restricts activities that may affect federally identified endangered and threatened species or their habitats through the implementation of operating limitations or restrictions or a temporary, seasonal or permanent ban on operations in affected areas.

These U.S. laws and their implementing regulations, as well as state counterparts, generally restrict the level of pollutants emitted to ambient air, discharges to surface water and disposals or other releases or threats of release to surface, soils and groundwater. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil and criminal penalties, the imposition of investigatory, remedial and corrective action obligations, the incurrence of capital expenditures, the occurrence of delays in the permitting, development or expansion of projects and the issuance of orders enjoining some or all of our future operations in a particular area. Certain environmental laws impose strict joint and several liability, without regard to fault or legality of conduct, for costs required to clean up and restore sites where hazardous substances or other wastes have been disposed of or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, wastes or other materials into the environment. In addition, these laws and regulations may restrict the rate of natural gas and NGL production or underground injection, disposal and sequestration of CO_2. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance will not have a material adverse effect on our business and operating results.

In addition, as a result of these environmental, health and safety laws and regulations, and their impact on our operations, we rely on specialized contracted companies to perform the majority of the specialized services inherent in the oil and gas industry. As such, we rely on the ability of these contractors to provide trained labor and properly designed and maintained equipment unique to their services. With the cyclical nature of the oil and gas business, the personnel used by these specialized contractors to perform these services may differ significantly in experience levels. From time to time, these specialized contractors may use new personnel that are still in training or may further sub-contract these services to other companies or personnel. There is a risk that these sub-contractors are unqualified or under-trained or that their equipment is not properly designed or maintained, which could result in work being performed inadequately or unsafely.

Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the oil and gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or production or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected.

Our gathering systems and processing, treating and fractionation facilities are subject to state regulation that could have a material adverse effect on our operations and cash flows*.*

State regulation of gathering systems and processing, treating and fractionation facilities includes safety and environmental requirements. In addition, several of our gas gathering systems are also subject to non-discriminatory take requirements and complaint-based state regulation with respect to our rates and terms and conditions of service. Our NGL gathering pipelines and operations may also be or become subject to state public utility or related jurisdiction which could impose additional safety and operational regulations relating to the design, siting, installation, testing, construction, operation, replacement and management of NGL gathering facilities. State and local regulation may cause us to incur additional costs, limit our operations, or prevent us from choosing the customers to which we provide service, any or all of which could have a material adverse effect on our operations and revenue.

The Temple Plants are subject to the rules and regulations of the PUCT and ERCOT, which could have a material adverse effect on our operations and cash flows.

The Temple Plants are subject to the rules and regulations of the PUCT and ERCOT. These regulations can impact the operations of generation facilities, which in turn can impact associated costs and revenues. For example, the PUCT implemented rules regarding weatherization of power plants in the aftermath of Winter Storm Uri. Such rules increased capital and operations and maintenance costs for many generation facilities. Additionally, the PUCT is currently weighing a redesign of the ERCOT market that is intended to retain existing generation facilities and encourage the construction of new generation facilities. This process could lead to decreased revenue, increased operating costs, and adversely affect our business, financial condition, and results of operations.

In addition, from time to time, ERCOT makes changes to its protocols or takes out of market actions that impact the wholesale power market. These regulations may cause us to incur additional costs or face delays, or otherwise could have a material adverse effect on our operations and cash flows.

We may face unanticipated water and other waste disposal costs as a result of increased water-related regulations.

We may be subject to regulation that restricts our ability to discharge water produced as part of our natural gas and NGL production operations. Productive zones frequently contain water that must be removed for the natural gas and NGLs to produce, and our ability to remove and dispose of sufficient quantities of water from the various zones will determine whether we can produce natural gas and NGLs in commercial quantities. The produced water must be transported from the leasehold and/or injected into disposal wells. The availability of disposal wells with sufficient capacity to receive all of the water produced from our wells may affect our ability to produce our wells. Also, the cost to transport and dispose of that water, including the cost of complying with regulations concerning water disposal, may reduce our profitability. Where water produced from our projects fails to meet the quality requirements of applicable regulatory agencies, our wells produce water in excess of the applicable volumetric permit limits, the disposal wells fail to meet the requirements of all applicable regulatory agencies or we are unable to secure access to disposal wells with sufficient capacity to accept all of the produced water, we may have to shut in wells, reduce drilling activities or upgrade facilities for water handling or treatment. The costs to dispose of this produced water may increase if any of the following occur:

- we cannot obtain future permits from applicable regulatory agencies;
- water of lesser quality or requiring additional treatment is produced;
- our wells produce excess water;

- new laws and regulations require water to be disposed in a different manner; or
- costs to transport the produced water to the disposal wells increase.

In June 2016, the EPA adopted effluent limitations for the treatment and discharge of wastewater resulting from onshore unconventional natural gas, NGL and oil extraction facilities to publicly owned treatment works. The disposal of fluids gathered from natural gas, NGL and oil producing operations in underground disposal wells has been pointed to by some groups and regulators as a potential cause of increased induced seismic events in certain areas of the country, particularly in Oklahoma, Texas, Colorado, Kansas, New Mexico and Arkansas. Certain states have begun to consider or adopt laws and regulations that may restrict or otherwise prohibit oilfield fluid disposal in certain areas or underground disposal wells, and state agencies implementing those requirements may issue orders directing certain wells in areas where seismic incidents have occurred to restrict or suspend disposal well operations or impose standards related to disposal well construction and monitoring. Any one or more of these developments could also increase our cost to dispose of our produced water.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Our natural gas gathering operations are generally exempt from the jurisdiction and regulation of the Federal Energy Regulatory Commission ("FERC"), except for certain anti-market manipulation provisions. Section 1(b) of the Natural Gas Act ("NGA") exempts natural gas gathering facilities from regulation by FERC as a natural gas company as defined under that statute. We believe the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gathering pipeline not subject to regulation by FERC. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is fact intensive and the subject of ongoing litigation. If FERC were to consider the status of our gathering systems and determine that they are subject to FERC regulation, the rates for, and terms and conditions of, services provided by those gathering systems would be subject to modification by FERC under the NGA or the Natural Gas Policy Act ("NGPA"). Such regulation could decrease revenue, increase operating costs, and adversely affect our business, financial condition, and results of operations. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA or NGPA, it could result in the imposition of civil penalties as well as a requirement to disgorge charges collected for such services in excess of the rates established by FERC.

The pipelines used to gather and transport natural gas we produce are subject to regulation by the DOT under the Natural Gas Pipeline Safety Act of 1968, as amended, the Pipeline Safety Act of 1992, as reauthorized and amended, and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Pipeline Safety Act"). The Pipeline and Hazardous Materials Safety Administration ("PHMSA") has established a risk-based approach to determine which gathering pipelines are subject to regulation and what safety standards regulated gathering pipelines must meet. In April 2016, pursuant to one of the requirements of the 2011 Pipeline Safety Act, PHMSA published a proposed rulemaking that would expand integrity management requirements and impose new pressure testing requirements on currently regulated gas gathering and transmission pipelines. The proposal would also significantly expand the regulation of gas gathering lines, subjecting previously unregulated pipelines to requirements regarding damage prevention, corrosion control, public education programs, and maximum allowable operating pressure limits, among others. In October 2019, PHMSA submitted three major rules to the Federal Register, including rules focused on: the safety of gas transmission pipelines (the first of three parts of the so-called "Gas Mega Rule"), the safety of hazardous liquid pipelines and enhanced emergency order procedures. The gas transmission rule requires operators of gas transmission pipelines constructed before 1970 to determine the material strength of their lines by reconfirming the maximum allowable operating pressure. In addition, the rule updates reporting and records retention standards for gas transmission pipelines.

The final of the three components of the Gas Mega Rule was published on August 24, 2022 and took effect on May 24, 2023. The Gas Mega Rule imposes new standards for pipeline inspections and repairs and empowers PHMSA with expanded authority to issue emergency orders.

The adoption of laws or regulations that apply more comprehensive or stringent safety standards could require us to install new or modified safety controls, pursue new capital projects, or conduct maintenance programs on an accelerated basis, all of which could require us to incur increased operating costs that could be significant. In addition, should we fail to comply with PHMSA or comparable state regulations, we could be subject to substantial fines and penalties. As of January 2023, the maximum civil penalties PHMSA can impose are $257,664 per pipeline safety violation per day, with a maximum of $2,576,627 for a related series of violations.

Restrictions on drilling, completion, production or related activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Natural gas and NGL operations in our operating areas can be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife, such as those restrictions imposed under the ESA. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs. Permanent restrictions imposed to protect endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration, development and production activities that could have an adverse impact on our ability to develop and produce our reserves. To the extent species are listed or re-designated under the ESA or similar state laws, or previously unprotected species are designated as threatened or endangered in areas where our properties are located, operations on those properties could incur increased costs arising from species protection measures and face delays or limitations with respect to production activities thereon. There is also increasing interest in nature-related matters beyond protected species, such as general biodiversity, which may similarly require us to incur costs or take other measures which may materially impact our business or operations.

Potential transactions that could benefit our stockholders may be subject to regulatory review and approval requirements, including pursuant to foreign investment regulations and review by governmental entities such as the Committee on Foreign Investment in the United States ("CFIUS"), or may be ultimately prohibited.

Potential transactions we consider may be subject to regulatory review and approval requirements by governmental entities, or ultimately prohibited. For example, CFIUS has authority to review direct or indirect foreign investments in U.S. companies. Among other things, CFIUS is empowered to require certain foreign investors to make mandatory filings, to charge filing fees related to such filings, and to self-initiate national security reviews of foreign direct and indirect investments in U.S. companies if the parties to that investment choose not to file voluntarily. In the case that CFIUS determines an investment to be a threat to national security, CFIUS has the power to unwind or place restrictions on the investment. Whether CFIUS has jurisdiction to review an acquisition or investment transaction depends on, among other factors, the nature and structure of the transaction, including the level of beneficial ownership interest and the nature of any information or governance rights involved. For example, investments that result in "control" of a U.S. business by a foreign person always are subject to CFIUS jurisdiction. CFIUS's expanded jurisdiction under the Foreign Investment Risk Review Modernization Act of 2018 and implementing regulations that became effective on February 13, 2020 further includes investments that do not result in control of a U.S. business by a foreign person but afford certain foreign investors certain information or governance rights in a U.S. business that has a nexus to "critical technologies," "critical infrastructure" and/or "sensitive personal data."

For so long as Banpu retains a material ownership interest in us, we may be deemed a "foreign person" under the regulations relating to CFIUS. As such, potential transactions involving a U.S. business or foreign business with U.S. subsidiaries that we may wish to pursue may be subject to CFIUS review. If a particular transaction falls within CFIUS's jurisdiction, we may determine that we are required to make a mandatory filing or that we will submit to CFIUS review on a voluntary basis, or to proceed with the transaction without submitting to CFIUS and risk CFIUS intervention, before or after closing the transaction. CFIUS may decide to block or delay transactions that could benefit our stockholders, impose conditions with respect to such transactions or request the President of the United States to order us to divest all or a portion of the assets or companies we acquired without first obtaining CFIUS approval, which may limit the attractiveness of, delay or prevent us from pursuing certain target companies or assets that we believe would otherwise be beneficial to us and our stockholders, any of which could have a material adverse effect on our financial condition, results of operations and cash flows.

Our sales of natural gas and NGLs, and any hedging activities related to such commodities, expose us to potential regulatory risks.

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

Additionally, the Federal Trade Commission and the Commodity Futures Trading Commissions (the “CFTC”) hold statutory authority to monitor certain segments of the physical and futures energy commodities markets relevant to our business. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales of natural gas and NGLs, and any hedging activities related to these energy commodities, we are required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. Failure to comply with such regulations, as interpreted and enforced, could materially and adversely affect our financial condition, results of operations and cash flows.

The adoption of derivatives legislation and regulations by Congress related to derivative contracts could have an adverse impact on our ability to hedge risks associated with our business.

Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”) establishes federal oversight and regulation of over-the-counter (“OTC”) derivatives and requires the CFTC and the SEC to enact further regulations affecting derivative contracts, including the derivative contracts we use to hedge our exposure to price volatility through the OTC market. Although the CFTC and the SEC have issued final regulations in certain areas, final rules in other areas and the scope of relevant definitions and/or exemptions still remain to be finalized.

In one of its rulemaking proceedings still pending under the Dodd-Frank Act, the CFTC issued on December 5, 2016, a re-proposed rule imposing position limits for certain futures and option contracts in various commodities (including natural gas, NGL and oil) and for swaps that are their economic equivalents. Under the proposed rules on position limits, certain types of hedging transactions are exempt from these limits on the size of positions that may be held, provided that such hedging transactions satisfy the CFTC’s requirements for certain enumerated “bona fide hedging” transactions or positions. A final rule has not yet been issued. Similarly, on December 2, 2016, the CFTC has reissued a proposed rule regarding the capital a swap dealer or major swap participant is required to set aside with respect to its swap business, but the CFTC has not yet issued a final rule.

The CFTC has also adopted final rules regarding aggregation of positions, under which a party that controls the trading of, or owns 10% or more of the equity interests in, another party will have to aggregate the positions of the controlled or owned party with its own positions for purposes of determining compliance with position limits unless an exemption applies. The CFTC’s aggregation rules are now in effect, though CFTC staff have granted relief from various conditions and requirements in the final aggregation rules until the earlier of August 12, 2025 and the effective date of any rulemaking that codifies the relief. With the implementation of the final aggregation rules and upon the adoption and effectiveness of the final CFTC position limits rules, our ability to execute our hedging strategies described above could be limited. It is uncertain at this time whether, when and in what form the CFTC’s proposed new position limits rules may become final and effective.

The CFTC issued a final rule on margin requirements for uncleared swap transactions on January 6, 2016, which includes an exemption from any requirement to post margin to secure uncleared swap transactions entered into by commercial end-users in order to hedge commercial risks affecting their business.

In addition, the CFTC has issued a final rule authorizing an exemption from the otherwise applicable mandatory obligation to clear certain types of swap transactions through a derivatives clearing organization and to trade such swaps on a regulated exchange, which exemption applies to swap transactions entered into by commercial end-users in order to hedge commercial risks affecting their business. The mandatory clearing requirement currently applies only to certain interest rate swaps and credit default swaps, but the CFTC could act to impose mandatory clearing requirements for other types of swap transactions. The Dodd-Frank Act also imposes recordkeeping and reporting obligations on counterparties to swap transactions and other regulatory compliance obligations.

All of the above regulations could increase the costs to us of entering into financial derivative transactions to hedge or mitigate our exposure to commodity price volatility and other commercial risks affecting our business. While it is not possible at this time to predict when the CFTC will issue final rules applicable to position limits or capital requirements, depending on our ability to satisfy the CFTC's requirements for a commercial end-user using swaps to hedge or mitigate our commercial risks, these rules and regulations may require us to comply with position limits and with certain clearing and trade-execution requirements in connection with our financial derivative activities. When a final rule on capital requirements for swap dealers is issued, the Dodd-Frank Act may require our current swap dealer counterparties to post additional capital as a result of entering into uncleared financial derivatives with us, which capital requirements rule could increase the costs to us of future financial derivatives transactions. The Volcker Rule provisions of the Dodd-Frank Act may also require our current bank counterparties that engage in financial derivative transactions to spin off some of their derivatives activities to separate entities, which separate entities may not be as credit-worthy as the current bank counterparties. Under such rules, other bank counterparties may cease their current business as hedge providers. These changes could reduce the liquidity of the financial derivatives markets thereby reducing the ability of entities like us, as commercial end-users, to have access to financial derivatives to hedge or mitigate our exposure to commodity price volatility.

As a result, the Dodd-Frank Act and any new regulations issued thereunder could significantly increase the cost of derivative contracts (including through requirements to post cash collateral), which could adversely affect our capital available for other commercial operations purposes, materially alter the terms of future swaps relative to the terms of our existing bilaterally negotiated financial derivative contracts and reduce the availability of derivatives to protect against commercial risks we encounter.

If we reduce our use of derivative contracts as a result of the new requirements, our results of operations may become more volatile and cash flows less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of commodity prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to natural gas, NGLs and oil. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial condition, results of operations and cash flows.

Potential future legislation or the imposition of new or increased taxes or fees may generally affect the taxation of natural gas, NGL and oil exploration and development companies and may adversely affect our cash flows.

Since 2020, there have been a significant number of federal and state level legislative proposals that, if enacted into law, would make significant changes to tax laws, including to certain key U.S. federal and state income tax provisions currently available to natural gas, NGL and oil exploration and development companies. For example, in late 2021 the U.S. House of Representatives passed legislation that was not ultimately enacted and, in early 2022, the Biden administration set forth several tax proposals, that would, if ultimately enacted into law, make significant changes to U.S. tax laws. Such proposals include, but are not limited to, (i) an increase in the U.S. federal income tax rates applicable to corporations, (ii) the repeal of the percentage depletion allowance for certain natural gas, NGL and oil properties, (iii) the elimination of current deductions for intangible drilling and development costs and (iv) an increase in the amortization period for geological and geophysical costs paid or incurred in connection with the exploration for, or development of, oil or natural gas, NGL and oil within the United States. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could take effect. Additionally, the states in which we operate or own assets may impose new or increased taxes or fees on natural gas, NGL and oil extraction. The passage of any legislation as a result of these proposals and other similar changes in U.S. federal income tax laws or the imposition of new or increased taxes or fees on natural gas, NGL and oil extraction could adversely affect our operations and cash flows.

Our tax liabilities potentially are subject to periodic audits by U.S. federal, state and local taxing authorities. Although we believe we have used reasonable interpretations and assumptions in calculating our tax liabilities, the final determination of these tax audits and any related proceedings cannot be predicted with certainty. Any adverse outcome of any such tax audits or related proceedings could result in unforeseen tax-related liabilities that may, individually or in the aggregate, materially affect our cash tax liabilities, and, as a result, our business, financial condition, results of operations, and liquidity.

Our business is subject to complex and evolving laws and regulations regarding privacy and data protection.

The regulatory environment surrounding data privacy and protection is constantly evolving and can be subject to significant change. New laws and regulations governing data privacy and the unauthorized disclosure of personal or confidential information pose increasingly complex compliance challenges and could potentially elevate our costs. Any failure to comply with these laws and regulations could result in significant penalties and legal liability. We continue to monitor and assess the impact of these laws, which in addition to penalties and legal liability, could impose significant costs for investigations and compliance, require us to change our business practices and carry significant potential liability for our business should we fail to comply with any such applicable laws.

Risks Related to Our Relationship with Banpu and its Affiliates

Banpu is our controlling stockholder and exercises substantial influence over us, and your ability to influence matters requiring stockholder approval may be limited.

Upon completion of this offering, Banpu will indirectly own approximately % of our outstanding common stock (or approximately % if the underwriters exercise in full their option to purchase additional shares). Our outstanding common stock is entitled to one vote per share. As a result of its ownership of our common stock, Banpu will indirectly own approximately % of the combined voting power of our common stock immediately after completion of this offering (or approximately % if the underwriters exercise in full their option to purchase additional shares). As a result of this ownership, Banpu has a substantial influence on our affairs and its voting power will constitute a substantial percentage of any quorum of our stockholders voting on any matter requiring the approval of our stockholders. Such matters include the election of directors, the adoption of amendments to our certificate of incorporation and bylaws and the approval of mergers or the sale of all or substantially all of our assets. Banpu's control or significant influence over us also may delay, defer or prevent an acquisition by a third party or other change of control of our Company and may make some transactions more difficult or impossible without the support of Banpu, even if such events are in the best interests of our other stockholders.

In addition, pursuant to our Stockholders' Agreement, for so long as BNAC and Banpu beneficially own 10% or more of our voting stock, BNAC will be entitled to designate for nomination to our board of directors a number of individuals approximately proportionate to such beneficial ownership, provided that (i) from the completion of this offering until the first anniversary of the completion of this offering, at least three board seats will not be BNAC designees, (ii) from and after the first anniversary of the completion of this offering until the first date on which BNAC and Banpu beneficially own 50% or less of our voting stock, at least four board seats will not be BNAC designees, and (iii) from and after the first date on which BNAC and Banpu beneficially own 50% or less of our voting stock, a number of board seats equal to the minimum number of directors that would constitute a majority of the total number of directors comprising our board of directors will not be BNAC designees. See "*Management — Controlled Company*," "*Principal Stockholders"* and "*Certain Relationships and Related Party Transactions — Stockholders' Agreement*."

Further, if, after this initial public offering, any person or group (other than Banpu and its controlled affiliates, excluding portfolio companies and operating companies) acquires 35% or more of our equity interests, or if any person or group acquires a greater percentage of our equity interests than are then held by Banpu and its controlled affiliates (excluding portfolio companies and operating companies of Banpu), such event will be an event of default under the RBL Credit Agreement, which may result in the amounts owed by us thereunder to become immediately due and payable.

Banpu also exercises substantial influence over the BKV-BPP Power Joint Venture, which we do not control, and the BKV-BPP Cotton Cove Joint Venture, which requires the consent of BPPUS for certain material actions. The BKV-BPP Power Joint Venture is controlled by its eight-member board of managers, four of whom are appointed by us and four of whom are appointed by BPPUS. The BKV-BPP Cotton Cove Joint Venture is controlled by its six-member board of managers, four of whom are appointed by BKV dCarbon Ventures (our wholly owned subsidiary) and two of whom are appointed by BPPUS. For additional information, see "*— Risks Related to Our Power Generation Business — We operate our power generation business through a joint venture which we do not control*" and "*— Risks Related to Our CCUS Business — We operate the Cotton Cove Project through a joint venture that requires the consent of BPPUS for certain material actions.*"

The interests of Banpu may differ from our interests or those of our other stockholders and the concentration of control in Banpu will limit other stockholders' ability to influence corporate matters. Banpu may take actions that our other stockholders do not view as beneficial or decline to take actions that our other stockholders view as beneficial, which may adversely affect our business, financial condition and results of operations. In addition, Banpu's control or significant influence over us may have an adverse effect on the price of our common stock.

Historically we have relied on Banpu and its affiliates for capital investments sufficient to fund our business operations. Banpu has no obligation to make any further capital investments or to provide additional loan proceeds.

Prior to the consummation of this offering, we have relied on Banpu and its affiliates for the capital investments necessary to fund our business through loan proceeds and other contributions. Following this offering, Banpu and its affiliates will have no obligation to provide any additional funding, and instead, we expect to fund our capital expenditures for our upstream, midstream and power businesses through cash flows from operations and from borrowings under our RBL Credit Agreement. We expect to fund up to 50% of our CCUS business from a variety of external sources, which may include joint ventures, project-based equity partnerships and federal grants, with the remaining capital needs being funded with cash flows from operations. Our future operating performance and to meet our debt service obligations will be affected by economic and capital market conditions, commodity prices, our results of operations and other factors, many of which are beyond our control.

Restrictive covenants in the agreements governing the indebtedness of Banpu may limit our ability to incur additional debt.

The agreements governing the indebtedness of Banpu require it to maintain certain financial ratios and tests based on consolidated financial statements. Immediately after completion of this offering, Banpu, or a subsidiary of Banpu, will continue to have a substantial influence on our affairs and its voting power will constitute a substantial percentage of any quorum of our stockholders voting on any matter requiring the approval of our stockholders. As a result, Banpu may prevent us from taking corporate actions that could cause Banpu to fail to comply with the applicable provisions of its debt agreements, even when such actions are in our best interests and the interests of our other stockholders. This limitation may materially adversely affect our ability to obtain future financing or fund needed capital expenditures.

We expect to be a "controlled company" within the meaning of the NYSE rules and, as a result, will qualify for and could rely on exemptions from certain corporate governance requirements.

Upon the completion of this offering, Banpu will beneficially control a majority of the combined voting power of all classes of our outstanding voting stock. Pursuant to our Stockholders' Agreement, BNAC, through ownership interests in us held by BNAC and its affiliates, will have certain rights to designate individuals for nomination to our board of directors. "*Certain Relationships and Related Party Transactions — Stockholders' Agreement*" contains additional information regarding these risks. As a result, we expect to be a controlled company within the meaning of the NYSE corporate governance standards. Under the NYSE rules, a company of which more than 50% of the voting power is held by another person or group of persons acting together is a controlled company and may elect not to comply with certain NYSE corporate governance requirements, including the requirements that:

- a majority of the board of directors consist of independent directors;
- the corporate governance and nominating committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities;
- the compensation committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities; and
- there be an annual performance evaluation of the nominating and governance and compensation committees.

These requirements will not apply to us as long as we remain a controlled company. Following this offering, we may utilize some or all of these exemptions. Accordingly, you may not have the same protections afforded to stockholders of companies that are subject to all of the corporate governance requirements of the NYSE. "*Management — Controlled Company*" contains additional information regarding these risks.

Banpu's interests, including interests in certain corporate opportunities, may conflict with our interests and the interests of our other stockholders. Conflicts of interest between us and Banpu could be resolved in a manner unfavorable to us and our other stockholders.

Banpu could have interests that differ from, or conflict with, the interests of our other stockholders and could cause us to take certain actions even if the actions are not favorable to us or our other stockholders or are opposed by our other stockholders. Potential conflicts of interest or disputes may arise between Banpu and us in a number of areas relating to our past or ongoing relationships, including:

- tax, employee benefits, indemnification and other matters arising from this offering;
- employee retention and recruiting;
- corporate opportunities that may be attractive to both Banpu and us;
- the arrangements governing the BKV-BPP Power Joint Venture, BKV-BPP Cotton Cove Joint Venture and any other new commercial arrangements between the Company and affiliates of Banpu in the future; and
- sales or other disposals by Banpu of all or a portion of its interest in us.

We may not be able to resolve potential conflicts and disputes with Banpu and even if we do, the resolution may be less favorable to us than if we were dealing with an unaffiliated third party. Because we are controlled or significantly influenced by Banpu, we may not have the leverage to negotiate amendments to the arrangements governing the BKV-BPP Power Joint Venture or BKV-BPP Cotton Cove Joint Venture (if any are required) on terms as favorable to us as those we would negotiate with an unaffiliated third party.

Additionally, there can be no assurance that Banpu will not engage in competition with us in the future. Our certificate of incorporation provides that, to the fullest extent permitted by law, neither Banpu nor its affiliates or any director who is not employed by us (including any non-employee director who serves as one of our officers in both his or her director and officer capacities) or his or her affiliates will have any duty to refrain from (i) engaging in the same or similar business activities or lines of business in which we or our affiliates now engage or propose to engage or (ii) otherwise competing with us or our affiliates. In addition, to the fullest extent permitted by law, in the event that Banpu or its affiliates or any non-employee director acquires knowledge of a potential transaction or other business opportunity that may be a corporate opportunity for itself, himself or herself or its or his or her affiliates or for us or any of our affiliates, such person will have no duty to communicate or offer such transaction or business opportunity to us or any of our affiliates and they may take any such opportunity for themselves or offer it to another person or entity.

Our certificate of incorporation also renounces, to the fullest extent permitted by law, any interest or expectancy that we have in, or right to be offered an opportunity to participate in, specified business opportunities that are from time to time presented to our officers, directors or stockholders or their respective affiliates, other than those officers, directors, stockholders or affiliates who are our or our subsidiaries' employees.

Generally, neither Banpu nor our non-employee directors who also are directors, officers, employees, agents or affiliates of Banpu or its affiliates (other than us) will be liable to us or our stockholders for breach of any fiduciary duty solely by reason of the fact that any such person pursues or acquires any corporate opportunity for, or recommends or transfer any corporation opportunity to, Banpu or its affiliates (other than us), rather than to us. This renunciation will not extend to corporate opportunities expressly offered to one of our non-employee directors solely in his or her capacity as our director or officer.

These provisions create the possibility that a corporate opportunity of our Company may be used for the benefit of Banpu and may significantly impair our ability to grow. In addition, Christopher Kalnin serves as a member of Banpu's Executive Committee with responsibilities to Banpu to, among other things, manage all aspects of Banpu's business in North America. Although our corporate opportunity policy requires Mr. Kalnin to present applicable business opportunities sourced by him to our company before such opportunities may be presented to Banpu, Banpu or its affiliates may compete with us for acquisition or other business opportunities. For additional information about our corporate opportunity policy and limitations on our access to business opportunities sourced by our officers or directors, see "*Management — Conflicts of Interest*."

Certain of our officers and directors may have actual or potential conflicts of interest because of their positions with Banpu or its affiliates and/or their ownership of common stock or equity awards in Banpu or its affiliates.

Christopher Kalnin currently serves as a member of Banpu's Executive Committee with responsibilities to Banpu to, among other things, manage all aspects of Banpu's business in North America. Following this offering, seven of our directors will be employees of Banpu or its affiliates. In addition, certain of our officers and such directors may now or in the future own capital stock or equity awards in Banpu or its affiliates. For certain of these individuals, their holdings of common stock or equity awards in Banpu or its affiliates may be significant compared to their total assets. Their position at Banpu or its affiliates and the ownership of capital stock or equity awards in Banpu or its affiliates creates, or may create the appearance of, conflicts of interest when these directors and officers are faced with decisions that could have different implications for Banpu than for us. These decisions could include:

- corporate opportunities;
- the impact that operating or capital decisions (including the incurrence of indebtedness) relating to our business may have on Banpu's consolidated financial statements or current or future indebtedness (including related covenants);
- business combinations involving us;
- our dividend and stock repurchase policies;
- compensation and benefit programs and other human resources policy decisions;
- management stock ownership;
- the payment of dividends on our common stock; and
- determinations with respect to our tax returns.

As a result of these actual or apparent conflicts of interest, we may be precluded from pursuing certain growth initiatives or transactions that may be favorable to us or we may take certain actions even if the actions are not favorable to us or are opposed by our stockholders. For additional information about limitations on our access to business opportunities sourced by our officers or directors, see "*Management — Conflicts of Interest*."

If Banpu experiences a change in control, you may not realize any change-of-control premium on shares of our common stock and we may become subject to the control of a presently unknown third party. Further, Banpu may sell, or pledge as collateral for its existing or future indebtedness, the shares of our common stock that it owns.

After this offering, Banpu will own approximately % of our outstanding common stock (or approximately % if the underwriters exercise in full their option to purchase additional shares). Subject to the provisions of the lock-up agreement entered into in connection with this offering, Banpu will not be restricted from selling some or all of its shares of our common stock in a privately negotiated transaction or otherwise, and a sale of its shares, if sufficient in size, could result in a change of control of our Company. Further, Banpu will not be restricted from pledging as collateral for its indebtedness the shares of our common stock held by it.

The ability of Banpu to sell its shares of our common stock, with no requirement for a concurrent offer to be made to acquire all of the shares of our common stock held by our other stockholders, could prevent you from realizing any change-of-control premium on your shares of our common stock that may otherwise accrue to Banpu on its sale of our common stock. In addition, if Banpu were to pledge as collateral for its indebtedness the shares of our common stock held by it, and Banpu were to default under such indebtedness, the lenders thereunder could foreclose upon and sell such shares to satisfy Banpu's obligations under such indebtedness.

Further, any acquiror or successor of all or a substantial number of Banpu's shares of our common stock will be entitled to exercise Banpu's voting control with respect to us. Such third party may have interests that conflict with those of our other stockholders. Any acquiror or successor to which Banpu transfers a controlling interest in us may attempt to cause us to revise or change our plans and strategies, as well as the agreements between Banpu and us described in this prospectus.

Risks Related to the Offering and Our Common Stock

Our actual operating results and activities could differ materially from the guidance we have disclosed herein.

We have presented herein certain forecasted operating results, costs and activities, including, without limitation, our future expected drilling activity and production. Any such forward-looking guidance represents our management's estimates as of the date hereof, is based upon a number of assumptions that are inherently uncertain and is subject to numerous business, political, economic, competitive, financial and regulatory risks, including the risks described in this "*Risk Factors*" section and under "*Cautionary Statement Regarding Forward-Looking Statements.*" Many of these risks and uncertainties are beyond our control, such as declines in commodity prices and the speculative nature of estimating natural gas and NGL reserves and in projecting future rates of production. If any of these risks and uncertainties actually occur or the assumptions underlying our guidance are incorrect, our actual operating results, costs and activities may be materially and adversely different from our guidance. In addition, investors should also recognize that the reliability of any guidance diminishes the farther in the future that the data is forecast. In light of the foregoing, investors are urged to put our guidance in context and not to place undue reliance upon it.

We do not currently plan to, and may not in the future have sufficient available cash to, pay dividends on our common stock.

We do not currently plan to declare dividends on our shares of common stock, and any future determination to pay dividends will be made at the sole discretion of our board of directors after considering our general economic and business conditions, including, among other things, our financial condition and anticipated cash needs. Furthermore, under Delaware law, cash dividends on capital stock may only be paid from "surplus" or, if there is no "surplus," from the corporation's net profits for the then-current or the preceding fiscal year. Unless we operate profitably, our ability to pay dividends on our common stock would require the availability of adequate "surplus," which is defined as the excess, if any, of net assets (total assets less total liabilities) over capital. Events may occur, including a reduction in anticipated production volumes or realized prices or other events, which could materially impact the amount of surplus we may have and/or may result in insufficient available cash to enable us to pay dividends to our stockholders.

The payment of dividends on our common stock is subject to the discretion of our board of directors and the lack of dividend payments on our common stock could adversely affect the market price of our common stock.

Our stockholders will have no contractual or other legal right to dividends. The payment of any future dividends on our common stock will be at the discretion of our board of directors and any determination to pay dividends and the amount of any such dividends will depend on general economic and business conditions, our financial condition, capital requirements, results of operations, contractual limitations, legal, tax, regulatory and contractual restrictions and implications on the payment of dividends by us to our stockholders or by our subsidiaries to us, including the restrictions under our current and any future debt agreements, potential acquisition opportunities and the availability and desirability of financing alternatives, the need to service our indebtedness or other current and anticipated cash needs and any other factors our board of directors deem relevant. Our board of directors will have the authority to establish cash reserves for the prudent conduct of our business, and the establishment of or increase in those reserves could result in insufficient cash available for payment of dividends on our common stock. The lack of dividend payments on our common stock could adversely affect the market price of our common stock.

The agreements governing our indebtedness impose restrictions on dividend payments.

The RBL Credit Agreement contains, and any future debt agreement may contain, covenants that prohibit us from paying dividends on our common stock under certain circumstances. The RBL Credit Agreement permits the RBL Borrower and its restricted subsidiaries to pay (a) unlimited dividends to their stockholders (including BKV Corporation) if (1) the net leverage ratio (as defined in the RBL Credit Agreement) on a pro forma basis is less than or equal to 1.50 to 1.00 and (2) the pro forma available commitments are greater than or equal to 25% of the Loan Limit (as defined in the RBL Credit Agreement) and (b) dividends to their stockholders in an amount not to exceed 100% of Distributable Free Cash Flow (as defined in the RBL Credit Agreement) if (1) the net leverage ratio on a pro forma basis is less than or equal to 1.75 to 1.00 and (2) the pro forma available commitments are greater than or equal to 20% of the Loan Limit. There can be no assurance that we will generate sufficient cash flow to permit us to reduce leverage and pay dividends in compliance with the RBL Credit Agreement or any other debt agreement.

Restrictions on distributions to us by our subsidiaries and affiliates under agreements governing their future indebtedness could limit our ability to pay dividends to holders of our common stock. These agreements contain financial tests and covenants that our subsidiaries and affiliates must satisfy prior to making distributions. If any of our subsidiaries or affiliates is unable to satisfy these restrictions or is otherwise in default under such agreements, it would be prohibited from making distributions to us that could, in turn, limit our ability to pay dividends to holders of our common stock.

The requirements of being a public company, including compliance with the reporting requirements of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and the requirements of the Sarbanes-Oxley Act, may strain our resources, increase our costs and distract management, and we may be unable to comply with these requirements in a timely or cost-effective manner.

Upon becoming a public company, we will be required to comply with new laws, regulations and requirements, certain corporate governance provisions of Sarbanes-Oxley Act, related regulations of the SEC and the requirements of the NYSE, with which we were not required to comply as a private company.

Complying with these statutes, regulations and requirements will occupy a significant amount of our time and will significantly increase our costs and expenses. We will need to:

- institute a more comprehensive compliance function to test and conclude on the sufficiency of our internal control over financial reporting;
- comply with rules promulgated by the NYSE;
- prepare and distribute periodic public reports;
- establish new internal policies, such as those relating to insider trading; and
- involve and retain to a greater degree outside professionals in the above activities.

Furthermore, while we generally must comply with Section 404 of the Sarbanes-Oxley Act, we are not required to have our independent registered public accounting firm attest to the effectiveness of our internal control over financial reporting until our first annual report subsequent to our ceasing to be an “emerging growth company.” At any time, we may conclude that our internal controls, once tested, are not operating as designed or that the system of internal controls does not address all relevant financial statement risks. Once required to attest to the effectiveness of our internal control over financial reporting, our independent registered public accounting firm may issue a report that concludes it does not believe our internal control over financial reporting is effective. Compliance with Sarbanes-Oxley Act requirements may strain our resources, increase our costs and distract management; and we may be unable to comply with these requirements in a timely or cost-effective manner.

As a public company, we will be subject to significant regulatory oversight and reporting obligations under U.S. federal securities laws and the continuous scrutiny of securities analysts and investors. In addition, most members of our management team have limited experience managing a public company, interacting with public company investors, and complying with the increasingly complex laws pertaining to public companies. Our management team may not successfully or efficiently manage us as a public company. These new obligations and constituents require significant attention from our management team and could divert our management team’s attention away from the day-to-day management of our business, which could adversely affect our business, results of operations and financial condition.

Further, we expect that being a public company subject to these rules and regulations may make it more difficult and more expensive for us to obtain director and officer liability insurance and we may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. As a result, it may be more difficult for us to attract and retain qualified individuals to serve on our board of directors or as executive officers. We are currently evaluating these rules, and we cannot predict or estimate the amount of additional costs we may incur or the timing of such costs.

We have identified material weaknesses in our internal control over financial reporting and may identify additional material weaknesses in the future, or otherwise fail to maintain effective internal control over financial reporting, which could result in a restatement of our financial statements or cause us to fail to meet our reporting obligations.

As of June 30, 2024, material weaknesses continued to exist in our internal control over financial reporting. A “material weakness” is a deficiency, or combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis.

We did not design and maintain effective controls to communicate relevant information among departments to completely and accurately record and disclose transactions in the financial statements. This material weakness contributed to the following additional material weaknesses: we did not design and maintain effective controls related to (i) the accounting for stock awards and common stock with certain put rights, including the value and classification of such arrangements and (ii) the communication and evaluation of terms and conditions set forth in complex contracts, including certain of our commodity derivative contracts, relevant to our compliance with financial covenants and related disclosures. These material weaknesses resulted in audit adjustments to share capital and other mezzanine equity accounts and liquidity disclosures in the consolidated financial statements as of December 31, 2021 and for the year then ended.

In addition, we did not design and maintain effective controls related to the accounting for income taxes, which were not designed at a sufficient level of precision or rigor to prepare and review the tax rate reconciliation, return to provision, income tax provision, related income tax assets and liabilities, and disclosures in the consolidated financial statements. This material weakness resulted in audit adjustments to income tax benefit, income taxes payable to related party and deferred tax assets in the consolidated financial statements as of December 31, 2021 and for the year then ended, and an immaterial audit adjustment to the supplemental cash flows information for cash payments for income taxes and a reclassification between oil and gas production and other taxes payable and other accrued liabilities within *Note 11 — Accounts Payable and Accrued Liabilities* to our consolidated financial statements, included elsewhere in this prospectus, as of and for the year ended December 31, 2023.

Each of the material weaknesses described above could result in a misstatement of the aforementioned account balances or disclosures that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected.

We have begun to take steps towards remediating these material weaknesses primarily by designing and implementing additional internal controls, including those related to (i) the communication of relevant information across departments, (ii) the valuation and classification of stock awards and common stock with certain put rights, (iii) the communication and evaluation of terms and conditions included in complex contracts relevant to our compliance with financial covenants and related disclosures, and (iv) the preparation and review of the income tax rate reconciliation, return to provision, income tax provision, related income tax assets and liabilities, and income tax disclosures. Although we believe we are addressing the internal control deficiencies that led to these material weaknesses, the measures we have taken, and plan to take, may not be effective.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate control over financial reporting in the future, or that we will be able to comply with our obligations under Section 404 of the Sarbanes-Oxley Act.

We cannot assure you that we have identified all, or that we will not in the future have additional, material weaknesses. Material weaknesses may still exist when we report on the effectiveness of our internal control over financial reporting as required by reporting requirements under Section 404 of the Sarbanes-Oxley Act after the completion of this offering. If material weaknesses emerge related to financial reporting, we encounter difficulties in implementing or improving our internal controls or we otherwise fail to develop and maintain effective internal control over financial reporting, our reputation and operating results could be harmed, we could fail to meet our reporting obligations, or we may have a restatement of our financial statements. Ineffective internal control over financial reporting could also cause current and potential investors to lose confidence in our reported financial information, which would harm our business and likely have a negative effect on the trading price of our shares of common stock.

There is no existing market for our common stock, and we do not know if one will develop.

Prior to this offering, there has not been a public market for our common stock. We cannot predict the extent to which investor interest in the Company will lead to the development of an active trading market on the stock exchange on which we list our common stock or otherwise or how liquid that market might become. If an active trading market does not develop, anyone purchasing our common stock may have difficulty selling it. The initial public offering price for the common stock was determined by negotiations between us and the representatives of the underwriters and may not be indicative of prices that will prevail in the open market following this offering. Consequently, purchasers of our common stock may be unable to sell it at prices equal to or greater than the price paid.

The following factors could affect our stock price:

- quarterly variations in our financial and operating results;
- public reaction to our press releases, our other public announcements and our filings with the SEC;
- strategic actions by our competitors;
- changes in revenue or earnings estimates, or changes in recommendations or withdrawal of research coverage, by equity research analysts;
- speculation in the press or investment community;
- the failure of research analysts to cover our common stock;
- sales of our common stock by us or our stockholders, or the perception that such sales may occur;
- changes in accounting principles, policies, guidance interpretations or standards;
- additions or departures of key management personnel;

- actions by our stockholders;
- general market conditions, including, among other things, fluctuations in commodity prices;
- domestic and international political, economic, legal and regulatory factors unrelated to our performance; and
- the realization of any risks described in this "*Risk Factors*" section.

The stock markets in general have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock. Securities class action litigation has often been instituted against companies following periods of volatility in the overall market and in the market price of a company's securities. Such litigation, if instituted against us, could result in very substantial costs, divert our management's attention and resources and harm our business, operating results and financial condition.

Our governing documents, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock. The existence of significant stockholders, such as Banpu, may have similar effects.

Some provisions of our governing documents could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- providing for a classified board of directors;
- limitations on the removal of directors;
- limitations on the ability of our stockholders to call special meetings;
- establishing advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders;
- the requirement that the affirmative vote of the holders of at least 66⅔% in voting power of all the then-outstanding shares of our stock be obtained to amend and restate our existing bylaws or to remove directors;
- the requirement that the affirmative vote of the holders of at least 66⅔% in voting power of all the then-outstanding shares of our stock (or, if approved by at least 60% of our board of directors, a majority in voting power of all the then-outstanding shares of our stock) be obtained to amend our certificate of incorporation; and
- providing that the board of directors is expressly authorized to make, repeal, alter, amend and rescind our bylaws.

In addition, the existence of significant stockholders, such as Banpu, may have the effect of deterring hostile takeovers, delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may deem to be in the best interests of the Company. Moreover, Banpu's concentration of stock ownership in us may adversely affect the trading price of our common stock to the extent investors perceive a disadvantage in owning stock of a company with a significant stockholder.

Investors in this offering will experience immediate and substantial dilution of $ per share.

Based on an assumed initial public offering price of $ per share (the midpoint of the price range set forth on the cover of this prospectus), purchasers of our common stock in this offering will experience an immediate and substantial dilution of $ per share in the as adjusted net tangible book value per share of common stock from the initial public offering price.

Our net tangible book value as of June 30, 2024 was approximately $ million, or $ per share. After giving effect to the sale of the shares in this offering and further assuming the receipt of the estimated proceeds (after deducting estimated underwriting discounts and commissions and estimated offering expenses), our as adjusted net tangible book value as of June 30, 2024 would have been approximately $ per share. This dilution is due in large part to earlier investors having paid substantially less than the initial public offering price when they purchased their shares. "*Dilution*" contains additional information.

Future sales of our common stock in the public market, or the perception that such sales may occur, could reduce our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute your ownership in us.

We may issue additional shares of common stock or convertible securities in subsequent public offerings. After the completion of this offering, assuming the underwriters' option to purchase additional shares is fully exercised, we will have outstanding shares of common stock. This number includes shares of common stock that we are selling in this offering and shares of common stock that we may sell in this offering if the underwriters' option to purchase additional shares is fully exercised, which may be resold immediately in the public market. Immediately following the completion of this offering, Banpu will own shares of common stock, representing approximately % of our total outstanding common stock (or % if the underwriters' option to purchase additional shares is exercised in full) and management, directors and other employee and non-employee stockholders, collectively, will own shares of common stock, representing approximately % of our total outstanding common stock (or % if the underwriters' option to purchase additional shares is exercised in full). All such shares are restricted from immediate resale under the federal securities laws and all such shares are subject to the lock-up agreements between such parties and the underwriters described in "*Underwriting*" but may be sold into the market in the future.

Our Stockholders' Agreement will provide BNAC and its affiliates with the right, in certain circumstances, to require us to register their shares of our common stock constituting registrable securities under the Securities Act for sale into the public markets at any time following the date that is six months after the consummation of this offering. "*Shares Eligible for Future Sale*" and "*Certain Relationships and Related Party Transactions — Registration Rights*" contain additional information regarding such rights.

In addition, in connection with this offering, we intend to file a registration statement with the SEC on Form S-8 providing for the registration of shares of our common stock issuable or reserved for issuance under our equity incentive plans. Subject to the satisfaction of vesting conditions and the expiration of lock-up agreements, shares registered under the registration statement on Form S-8 will be available for resale immediately in the public market without restriction.

We cannot predict the size of future issuances of our common stock or securities convertible into common stock or the effect, if any, that future issuances and sales of shares of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares issued in connection with an acquisition or shares owned by Banpu and such other stockholders), or the perception that such sales could occur, may adversely affect prevailing market prices of our common stock.

Our common stock will not be entitled to preemptive rights to buy shares from us. As a result, stockholders will not have the automatic ability to avoid dilution in their percentage ownership of us.

Terms of subsequent financings may adversely impact stockholder equity.

If we raise more equity capital from the sale of common stock, institutional or other investors may negotiate terms more favorable than the current prices of our common stock. If we issue debt securities, the holders of the debt would have a claim to our assets that would be prior to the rights of stockholders until the debt is paid. Interest on these debt securities would increase costs and could negatively impact our operating results.

In accordance with Delaware law and the provisions of our certificate of incorporation, we may issue one or more classes or series of preferred stock that ranks senior in right of dividends, liquidation or voting to our common stock. Preferred stock may have such designations, preferences, limitations and relative rights, including preferences over our common stock respecting dividends and distributions, as our board of directors may determine, and the issuance of preferred stock would dilute the ownership of our existing stockholders. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the common stock. The terms of any series of preferred stock may also reduce or eliminate the amount of cash available for payment of dividends to our holders of common stock or subordinate the claims of our holders of common stock to our assets in the event of our liquidation. Our common stock will not be subject to conversion, redemption or sinking fund provisions.

The representatives of the underwriters of this offering may waive or release parties to the lock-up agreements entered into in connection with this offering, which could adversely affect the price of our common stock.

We, Banpu and all of our directors and executive officers have entered into lock-up agreements with respect to their ownership of our common stock, pursuant to which we and they are subject to certain resale restrictions for a period of 180 days following the effectiveness date of the registration statement of which this prospectus forms a part. The representatives of the underwriters, at any time and without notice, may release all or any portion of the common stock subject to the foregoing lock-up agreements. If the restrictions under the lock-up agreements are waived, then common stock will be available for sale into the public markets, which could cause the market price of our common stock to decline and impair our ability to raise capital. "*Underwriting*" provides additional information regarding the lock-up agreements.

If securities or industry analysts do not publish research or reports about our business, if they adversely change their recommendations regarding our common stock or if our operating results do not meet their expectations, our stock price could decline.

The trading market for our common stock will be influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of the Company or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn could cause our stock price or trading volume to decline. Moreover, if one or more of the analysts who cover the Company downgrades our common stock or if our operating results do not meet their expectations, our stock price could decline.

Our certificate of incorporation will designate the Court of Chancery of the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers, employees or agents.

Our certificate of incorporation will provide that unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware will, to the fullest extent permitted by law, be the sole and exclusive forum for any (i) derivative action or proceeding brought on behalf of the Company, (ii) action asserting a claim of breach of a fiduciary duty owed by any director, officer or employee of the Company to the Company or our stockholders, (iii) action asserting a claim against the Company or any director or officer of the Company arising pursuant to any provision of the Delaware General Corporation Law (the "DGCL") or our governing documents, or (iv) action asserting a claim against the Company or any director, officer or employee of the Company, which claim is governed by the internal affairs doctrine. Notwithstanding the foregoing sentence, the federal district courts of the United States of America shall be the exclusive forum for the resolution of any complaint asserting a cause of action arising under U.S. federal securities laws, including the Securities Act and the Exchange Act. This choice of forum may limit a stockholder's ability to bring a claim in a judicial forum that it finds favorable for disputes with us or our directors, officers, employees or agents, which may discourage such lawsuits against us and such persons. Alternatively, if a court were to find these provisions of our governing documents inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our financial condition, results of operations and cash flows.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This prospectus contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact included in this prospectus, regarding our strategy, future operations, financial position, estimated revenue and losses, projected costs, prospects, plans and objectives of management and dividend policy are forward-looking statements. When used in this prospectus, words such as “expect,” “project,” “estimate,” “believe,” “anticipate,” “intend,” “budget,” “plan,” “seek,” “envision,” “forecast,” “target,” “predict,” “may,” “should,” “would,” “could,” “will,” the negative of these term and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on our current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described under “*Risk Factors.*” These forward-looking statements are based on management’s current belief, based on currently available information, as to the outcome and timing of future events.

Forward-looking statements may include statements about, among other things:

- our business strategy;
- our reserves;
- our financial strategy, liquidity and capital required for our development programs;
- our relationship with Banpu, including future agreements with Banpu;
- actual and potential conflicts of interest relating to Banpu, its affiliates and other entities in which members of our officers and directors are or may become involved;
- estimated natural gas, NGL and oil prices;
- our dividend policy;
- the timing and amount of future production of natural gas, NGL and oil;
- our hedging strategy and results;
- our drilling plans;
- competition and government regulation;
- legal, regulatory or environmental matters;
- marketing of natural gas, NGL and oil;
- business or leasehold acquisitions and integration of acquired businesses;
- our ability to develop existing prospects;
- costs of developing our properties and of conducting our operations;
- our plans to establish midstream contracts that allow us to supply our own natural gas directly to the Temple Plants;
- our plan to continue to build out our power generation business and to expand into retail power;
- our ability to produce and sell Carbon Sequestered Gas;
- our ability to effectively operate and grow our CCUS business;
- our ability to forecast annual CO_2e sequestration rates for our CCUS projects;
- our ability to reach FID and execute and complete any of our pipeline of identified CCUS projects;
- our ability to identify and complete additional CCUS projects as we expand our upstream operations;
- our ability to effectively operate and grow our retail power business;
- our anticipated Scope 1, Scope 2 and Scope 3 emissions from our owned and operated upstream and natural gas midstream businesses and our sustainability plans and goals, including our plans to

offset our Scope 1, Scope 2 and Scope 3 emissions from our owned and operated upstream and natural gas midstream businesses;

- our ESG strategy and initiatives, including those relating to the generation and marketing of environmental attributes or new products seeking to benefit from ESG-related activities;
- the impact of the COVID-19 pandemic and its effects on our business and financial condition;
- general economic conditions;
- cost inflation;
- credit markets;
- our ability to service our indebtedness;
- our ability to expand our business, including through the recruitment and retention of skilled personnel;
- our future operating results;
- the remediation of our material weaknesses; and
- our plans, objectives, expectations and intentions.

The forward-looking statements included in this prospectus are based on current expectations and involve numerous risks and uncertainties, most of which are difficult or impossible to predict and many of which are beyond our control, incident to the exploration for and development, production and sale of natural gas, NGLs and oil. Assumptions relating to these forward-looking statements involve judgments, risks and uncertainties with respect to, among other things, market factors (including competition and inflation), market prices (including geographic basis differentials) of natural gas, NGLs and oil, results of future drilling and marketing activity, future production and costs (including availability of drilling and production equipment and services), legislative and regulatory initiatives, electronic, cyber or physical security breaches, drilling and other operating risks, environmental risks (including weather-related events), future business decisions, the uncertainty inherent in estimating natural gas, NGL and oil reserves and the other risks described under "*Risk Factors*."

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

Although we believe that the assumptions underlying these forward-looking statements are reasonable, should one or more of the risks or uncertainties described in this prospectus occur, or should underlying assumptions prove incorrect, actual outcomes and our results and financial condition may differ materially from those indicated in any forward-looking statements. In light of the significant uncertainties inherent in these forward-looking statements, the inclusion of such information should not be regarded as a representation by us or any other person that our objectives and plans will be achieved.

All forward-looking statements, expressed or implied, included in this prospectus are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

All forward-looking statements, expressed or implied, in this prospectus are based only on information currently available to us and speak only as of the date on which they are made. Except as otherwise required by applicable law, we disclaim any duty to publicly update any forward-looking statement, each of which is expressly qualified by the statements in this section, to reflect events or circumstances after the date of this prospectus.

USE OF PROCEEDS

We estimate that the net proceeds to us from the sale of our common stock in this offering, after deducting underwriting discounts and commissions and estimated offering expenses payable by us, will be approximately $ million (or approximately $ million if the underwriters exercise in full their option to purchase additional shares), based on an assumed initial public offering price of $ per share (the midpoint of the price range set forth on the cover page of this prospectus).

Each $1.00 increase (decrease) in the assumed initial public offering price of $ per share (the midpoint of the price range set forth on the cover page of this prospectus) would increase (decrease) the net proceeds to us from this offering by $ million, assuming that the number of shares offered by us, as set forth on the cover page of this prospectus, remains the same and after deducting underwriting discounts and commissions and estimated offering expenses payable by us. We may also increase or decrease the number of shares we are offering. Each increase (decrease) of 1.0 million shares in the number of shares we are offering would increase (decrease) the net proceeds to us from this offering by $ million, assuming that the assumed initial public offering price of $ per share (the midpoint of the price range set forth on the cover page of this prospectus) remains the same, and after deducting underwriting discounts and commissions and estimated offering expenses payable by us.

Of the net proceeds we receive from the sale of our common stock in this offering, we intend to use approximately $ million to repay certain indebtedness, which may include some or all of the $50.0 million in aggregate principal amount outstanding under the BNAC A&R Loan Agreement and the outstanding revolving borrowings under the RBL Credit Agreement, for growth capital expenditures and for other general corporate purposes, which may include the expansion of our CCUS business.

On June 11, 2024, the RBL Borrower drew down $425.0 million under the RBL Credit Agreement and we used such proceeds and cash on hand to pay off the amounts outstanding under the Term Loan Credit Agreement, the Revolving Credit Agreement and the SCB Credit Facility, which were each were terminated concurrently with the repayment of the remaining amounts owed thereunder. Subsequently, on June 27, 2024, we repaid $65.0 million, including interest, of the outstanding borrowings under the RBL Credit Agreement. As of August 12, 2024, there are $360.0 million of outstanding borrowings under the RBL Credit Agreement with an effective interest rate of 8.7%, and there are $50.0 million of outstanding borrowings under the BNAC A&R Loan Agreement with an effective interest rate of 10.4%. The BNAC A&R Loan Agreement and RBL Credit Agreement will mature on December 31, 2027 and June 12, 2028, respectively.

Amounts outstanding under the RBL Credit Agreement bear interest based upon SOFR or ABR (each as defined in the RBL Credit Agreement), as applicable, plus an additional margin which is based on the percentage of the borrowing base being utilized, ranging from 2.75% to 3.75% for SOFR loans and 1.75% to 2.75% for ABR loans. There is also a commitment fee of 0.50% on the undrawn commitments. Obligations under the RBL Credit Agreement may be prepaid without premium or penalty, other than customary breakage costs. For additional information, see "*Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Loan Agreements and Credit Facilities — RBL Credit Agreement*."

DIVIDEND POLICY

We currently do not pay a fixed cash dividend to holders of our common stock. Our dividend policy is under consideration by our board of directors. Any future determination related to our dividend policy will be made at the sole discretion of our board of directors after considering our general economic and business conditions, including our financial condition and results of operations, capital requirements, restrictions under our indebtedness, potential acquisition opportunities and other current and anticipated cash needs and any other factors our board of directors deems relevant.

CAPITALIZATION

The following table shows our capitalization as of June 30, 2024:

- on an actual basis; and
- on an as adjusted basis, after giving effect to the sale of shares of our common stock in this offering (which assumes that the underwriters do not exercise their option to purchase additional shares), at an assumed initial public offering price of $ per share (the midpoint of the price range set forth on the cover page of this prospectus), our receipt of the estimated net proceeds of this offering and after deducting underwriting discounts and commissions and estimated offering expenses payable by us and the application of such net proceeds as described under "*Use of Proceeds*."

The as adjusted information set forth in the table below is illustrative only and will adjust based on the actual initial public offering price and other terms of this offering determined when the initial public offering price is determined. You should read the following table together with "*Prospectus Summary — Summary Historical Financial Information*," "*Management's Discussion and Analysis of Financial Condition and Results of Operations*," "*Prospectus Summary — Summary Reserves, Production and Operating Data*," and our historical consolidated financial statements and the related notes thereto included elsewhere in this prospectus.

	As of June 30, 2024	
	Actual	**As Adjusted**
(in thousands, except shares and par value)	**(unaudited)**	
Cash and cash equivalents, including restricted cash	$ 9,197	$
Debt:		
Notes payable to related party[1]	$ 50,000	$
RBL Credit Agreement	360,000	
Total debt[2]	$ 410,000	$
Mezzanine equity[3]:		
Common stock – minority ownership puttable shares	$ 60,476	$
Equity-based compensation	129,412	
Total mezzanine equity	$ 189,888	$
Stockholders' equity[4]:		
Common stock, par value $0.01 per share; 300,000,000 authorized shares; 63,872,734 shares issued and outstanding, actual; and shares issued and outstanding, as adjusted[5]	$ 1,283	$
Treasury stock, shares at cost; 213,528 shares	(4,582)	
Additional paid-in capital	1,033,355	
Retained earnings	169,086	
Total stockholders' equity	$1,199,142	$
Total capitalization	$1,808,227	$

(1) Represents term loans under the BNAC A&R Loan Agreement. See "*Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Loan Agreements and Credit Facilities*."

(2) As of August 12, 2024, we had outstanding debt of $410.0 million, which consisted of (i) $360.0 million in aggregate principal amount of revolving borrowings under the RBL Credit Agreement and (ii) $50.0 million in aggregate principal amount under the BNAC A&R Loan Agreement.

(3) Holders of certain minority ownership shares of our common stock, shares of our common stock issued as stock compensation and shares of common stock purchased through our employee stock purchase program have the right, at their respective option, to require the Company to repurchase the

shares upon the occurrence of certain events. As a result, the fair value of these common shares is recognized within mezzanine equity in our condensed consolidated balance sheets.

(4) The number of shares of our common stock issued and outstanding on an actual basis has been adjusted to give effect to the one-for-two reverse stock split the Company completed on October 30, 2023. See "*Prospectus Summary — Reverse Stock Split.*"

(5) The number of shares of our common stock issued and outstanding on an as adjusted basis assumes that the underwriters will not exercise their option to purchase additional shares. If the underwriters exercise in full their option to purchase additional shares, as adjusted cash and cash equivalents, additional paid-in capital, total stockholders' equity, total capitalization and shares of common stock outstanding as of June 30, 2024 would have been $, $, $, $ and $, respectively.

The number of shares of our common stock set forth in the table above excludes an aggregate of 5,000,000 additional shares of our common stock reserved for awards pursuant to the 2022 Plan, including shares of common stock that may be issued upon vesting of equity awards that we expect to be granted in connection with this offering, and 500,000 shares of our common stock available for purchase by employees pursuant to the ESPP.

DILUTION

Purchasers of the common stock in this offering will experience immediate and substantial dilution in the net tangible book value per share of the common stock for accounting purposes. We calculate net tangible book value per share by dividing our tangible net worth (tangible assets less total liabilities) by the total number of outstanding shares of common stock.

Our net tangible book value as of June 30, 2024 was approximately $ million, or $ per share. After giving effect to the sale of the shares in this offering and further assuming the receipt of the estimated net proceeds (after deducting estimated underwriting discounts and commissions and estimated offering expenses), our as adjusted net tangible book value as of June 30, 2024 would have been approximately $ million, or $ per share. This represents an immediate increase in the net tangible book value of $ per share to our existing stockholders and an immediate dilution (*i.e.*, the difference between the initial public offering price per share of our common stock and the as adjusted net tangible book value per share of our common stock after this offering) to new investors purchasing shares of common stock in this offering of $ per share.

The following table illustrates the per share dilution to new investors purchasing shares of common stock in this offering:

Assumed initial public offering price per share		$
Net tangible book value per share as of June 30, 2024	$	
Increase in pro forma net tangible book value per share attributable to new investors in this offering		
Less: As adjusted net tangible book value per share of common stock after giving effect to this offering		
Dilution in as adjusted net tangible book value per share to new investors from this offering		$

A $1.00 increase (decrease) in the assumed initial public offering price of $ per share (the midpoint of the price range set forth on the cover page of this prospectus), would increase (decrease) the as adjusted net tangible book value per share after this offering by $ per share and increase (decrease) the dilution in net tangible book value per share to new investors in this offering by $ per share, in each case assuming the number of shares of common stock offered by us, as set forth on the cover page of this prospectus, remains the same and less estimated underwriting discounts and commissions and estimated offering expenses payable by us (and if the underwriters exercise in full their option to purchase additional shares, the as adjusted net tangible book value per share would be $ per share, and the dilution in net tangible book value per share to new investors in this offering would be $ per share).

The following table summarizes, as of June 30, 2024, the differences between the number of shares issued as a result of this offering, the total amount paid by existing shareholders and the average price per share to be paid by investors in this offering, based upon an assumed initial public offering price of $ per share (the midpoint of the price range set forth on the cover page of this prospectus).

	SHARES		TOTAL CONSIDERATION		AVERAGE PRICE PER SHARE
	NUMBER	PERCENT	AMOUNT	PERCENT	
Existing investors					
Existing common stock stockholders		%	$	%	$
Existing mezzanine equity stockholders[(1)]		%		%	
Total existing stockholders		%		%	
New investors		%		%	
Total		100%	$	100%	$

(1) Holders of certain minority ownership shares of our common stock have the right, at their option, to

require us to repurchase the shares upon the occurrence of certain events. As a result, the fair value of these common shares is recognized within mezzanine equity in our condensed consolidated balance sheets.

The above tables and related discussion are based on the number of shares of our common stock to be outstanding as of the closing of this offering. If the underwriters' option to purchase additional shares is exercised in full, the number of shares held by new investors will be increased to , or approximately % of the total number of shares of common stock. The above tables and related discussion exclude an aggregate 5,000,000 of additional shares of our common stock reserved for awards pursuant to the 2022 Plan, including shares of common stock that may be issued upon vesting of equity awards that we expect to be granted in connection with this offering, and 500,000 additional shares reserved to be available for purchase by employees pursuant to the ESPP.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our historical consolidated financial statements and related notes included elsewhere in this prospectus. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expectations. "Cautionary Statement Regarding Forward-Looking Statements" and "Risk Factors" (included elsewhere in this prospectus) contain important information. We disclaim any duty to publicly update any forward-looking statements except as otherwise required by applicable law.

In this section, references to "BKV," the "Company," "we," "us," and "our" refer to BKV Corporation and its subsidiaries, unless otherwise indicated or the context otherwise requires. For more information on our organizational structure, see "Note 1 — Business and Basis of Presentation" to our condensed consolidated financial statements included elsewhere in this prospectus. It is also described in "Note 1 — Business and Basis of Presentation" to our audited consolidated financial statements included elsewhere in this prospectus.

Overview

We are a forward thinking, growth driven energy company focused on creating value for our stockholders through the organic development of our properties as well as accretive acquisitions. Our core business is to produce natural gas from our owned and operated upstream businesses, which are supported by our four business lines: natural gas production; natural gas gathering, processing and transportation (our "natural gas midstream business"); power generation; and carbon capture, utilization and sequestration ("CCUS"). We expect our owned and operated upstream and natural gas midstream businesses to achieve net zero Scope 1 and Scope 2 emissions by the early 2030s, and net zero Scope 1, 2 and 3 emissions by the late 2030s. We maintain a "closed-loop" approach to our net zero emissions goal through the operation of our four business lines. We are committed to vertically integrating portions of our business to reduce costs and improve overall commercial optimization of the full value chain. For instance, in the Barnett, our natural gas production is gathered and transported in part through our midstream systems and we commenced sequestration operations at our first CCUS project in November 2023. We expect our second CCUS project to commence sequestration activities in the first half of 2026 and are evaluating a robust backlog of actionable CCUS opportunities. We believe that our differentiated business model, net zero emissions focus, highly experienced management team and technology-driven approach to operating our business will enable us to create stockholder value.

Operational and Financial Highlights

Below are some highlights of our operating and financial results for the six months ended June 30, 2024 and 2023 and the years ended December 31, 2023, 2022 and 2021:

- Production of natural gas, NGLs, and oil was approximately 147.0 Bcfe and 159.0 Bcfe during the six months ended June 30, 2024 and 2023, respectively. Production of natural gas, NGLs and oil was approximately 313.8 Bcfe, 279.5 Bcfe and 245.8 Bcfe during the years ended December 31, 2023, 2022 and 2021, respectively.
- Average realized product prices, excluding the impact of settled derivatives, were $1.82 per Mcfe and $2.22 per Mcfe for the six months ended June 30, 2024 and 2023, respectively. Average realized product prices, excluding the impact of settled derivatives, were $2.25 per Mcfe, $5.84 per Mcfe and $3.38 per Mcfe for the years ended December 31, 2023, 2022 and 2021, respectively.
- For the six months ended June 30, 2024 and 2023, production revenues were $267.5 million and $352.9 million, respectively, and midstream revenues were $7.5 million and $8.4 million respectively. For the years ended December 31, 2023, 2022 and 2021, production revenues were $706.2 million, $1.6 billion and $829.7 million, respectively, and midstream revenues were $16.2 million, $12.7 million and $6.9 million, respectively.
- Lease operating expense was $65.4 million, or $0.44 per Mcfe, and $76.0 million, or $0.48 per Mcfe, for the six months ended June 30, 2024 and 2023, respectively. Lease operating expense was

$142.9 million, or $0.46 per Mcfe, $123.4 million, or $0.44 per Mcfe, and $83.0 million, or $0.33 per Mcfe, for the years ended December 31, 2023, 2022 and 2021, respectively.

- Net loss for the six months ended June 30, 2024 was $98.3 million, and net income for the six months ended June 30, 2023 was $60.8 million. Net income attributable to common stockholders for the years ended December 31, 2023 and 2022 was $116.9 million and $410.1 million, respectively. Net loss attributable to common stockholders for the year ended December 31, 2021 was $170.7 million.
- Net cash provided by operating activities for the six months ended June 30, 2024 and 2023 was $9.8 million and $80.9 million, respectively. Net cash provided by operating activities for the years ended December 31, 2023, 2022 and 2021 was $123.1 million, $349.2 million and $358.1 million, respectively.
- Adjusted EBITDAX was $108.8 million and $117.0 million for the six months ended June 30, 2024 and 2023, respectively. Adjusted EBITDAX was $251.2 million, $575.5 million and $281.0 million for the years ended December 31, 2023, 2022 and 2021, respectively.
- Adjusted Free Cash Flow was positive $67.1 million and negative $11.4 million for the six months ended June 30, 2024 and 2023, respectively. Adjusted Free Cash Flow was $19.1 million, $169.2 million and $165.1 million for the years ended December 31, 2023, 2022 and 2021, respectively.
- Net cash provided by investing activities was $101.6 million for the six months ended June 30, 2024, which was due to the proceeds from the sales of assets of $133.3 million. The proceeds were offset by $21.5 million used for the development of natural gas properties and $7.1 million used to invest in CCUS activities. The remaining cash outflow is attributable to other investing activities. Net cash used in investing activities was $128.6 million for the six months ended June 30, 2023, and was primarily used for the development of natural gas properties. Net cash used in investing activities was $177.8 million for the year ended December 31, 2023, of which $134.4 million was used for the development of natural gas properties, $50.0 million was used to invest in CCUS activities, and $6.6 million was provided from other investing activities. Net cash used in investing activities was $865.6 million for the year ended December 31, 2022, $619.4 million of which was used to acquire assets in the Exxon Barnett Acquisition. The remaining cash outflow included $235.4 million attributable to development activities and $10.7 million of other investing activities. Net cash used in investing activities was $161.9 million for the year ended December 31, 2021, $88.4 million of which was used on the initial investment in the BKV-BPP Power Joint Venture. The remaining $73.5 million included $63.9 million attributable to development activities and $7.6 million for developed property and undeveloped acreage acquisition.
- During the year ended December 31, 2021, we paid a dividend to common stockholders of $88.1 million, or $0.75 per share of our common stock (without adjusting to give effect to our October 2023 reverse stock split). No dividends were paid during the six months ended June 30, 2024 or 2023 or the years ended December 31, 2023 or 2022.

Adjusted EBITDAX and Adjusted Free Cash Flow are not financial measures calculated in accordance with accounting principles generally accepted in the United States of America (“GAAP”). See “*Prospectus Summary — Summary Historical Financial Information — Non-GAAP Financial Measures”* for a description of each of these measures and a reconciliation of each of these measures to their most directly comparable GAAP measure.

Market Outlook

The natural gas and NGL industry is cyclical and commodity prices are highly volatile. According to the EIA, the historical high and low Henry Hub natural gas spot prices per MMBtu for the following periods were as follows: in 2021, high of $23.86 and low of $2.43; in 2022, high of $9.85 and low of $3.46; in 2023, high of $3.78 and low of $1.74; and for the six months ended June 30, 2024, high of $13.20 and low of $1.25.

We expect the natural gas and NGL markets to continue to be volatile in the future. Our revenue, profitability and future growth are highly dependent on the prices we receive for our natural gas and NGL production. See “*Risk Factors — Risks Related to Our Upstream Business and Industry — The volatility of* *natural gas and NGL prices due to factors beyond our control may materially and adversely affect our business, financial condition or results of operations and our ability to make capital expenditures and meet our debt service obligations and other financial commitments.*"

Our business has also been impacted by economic conditions and disruptions in global financial markets such as reduced energy demand, increased prices due to the impacts of pandemics, inflation, and labor shortages. There was uncertainty during 2023 with potential economic downturn or recession in parts of the United States and globally, which continues into 2024 with global conflicts such as the Russia-Ukraine and Israel-Hamas wars. Due to uncertainty in inflation, we may continue to see global, industry-wide supply chain disruptions and widespread shortages of labor, materials and services. Such shortages have resulted in our facing significant cost increases for labor, materials and services, and we expect these shortages and cost increases to continue. We are currently in a period of declining natural gas prices; however, the cost of labor, materials, and services remain high and may not adjust downward in proportion to increase in natural gas prices. We cannot predict the future inflation rate but to the extent inflation remains elevated, we may experience further cost increases in our operations, including costs for drill rigs, workover rigs, hydraulic fracturing fleets, tubulars and other well equipment, as well as increased labor costs. If we are unable to recover higher costs through increases in commodity prices or from our current revenue stream, then our estimates of future reserves, impairment assessments of natural gas and oil properties, and values of properties in purchase and sale transactions may all be significantly impacted. Although macroeconomic inflation is easing, these inflationary pressures may have an impact on our liquidity position when combined with the impact of rising interest rates on our variable rate debt. We expect to continue to achieve our business strategy by remaining vigilant in maintaining a disciplined financial strategy and in optimizing the value of our core business. We will also continue to monitor the impacts of inflation and commodity price volatility and the effects on our business, including to our customers and our partners.

How We Evaluate Our Business

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

- Adjusted EBITDAX;
- Upstream Reinvestment Rate;
- Adjusted Free Cash Flow;
- Adjusted Free Cash Flow Margin;
- Production Volume; and
- Total Net Leverage Ratio.

Adjusted EBITDAX. We define Adjusted EBITDAX as net income (loss) attributable to BKV Corporation before (i) non-cash derivative gains (losses), (ii) depreciation, depletion, amortization and accretion, (iii) exploration and impairment expense, (iv) gains (losses) on contingent consideration liabilities, (v) interest expense, (vi) interest expense, related party, (vii) income tax benefit (expense), (viii) equity-based compensation expense, (ix) bargain purchase gains, (x) earnings or losses from equity affiliate, (xi) the portion of settlements paid (received) for early-terminated derivative contracts that relate to future periods and (xii) other nonrecurring transactions. Adjusted EBITDAX is a supplemental non-GAAP financial measure that is used by our management and external users of our consolidated financial statements, such as industry analysts, investors, lenders, rating agencies and others to more effectively evaluate our operating performance and results of operations from period to period and against our peers. We believe Adjusted EBITDAX is a useful performance measure because it allows us to effectively evaluate our operating performance and results of operations from period to period and against our peers, without regard to our financing methods, corporate form or capital structure. See "*Prospectus Summary — Summary Historical Financial Information — Non-GAAP Financial Measures*" for a description of Adjusted EBITDAX and for a reconciliation of Adjusted EBITDAX to net loss, its most directly comparable GAAP measure.

Upstream Reinvestment Rate. Upstream Reinvestment Rate for any period refers to our total capital expenditures accrued for the development of natural gas properties (excluding leasehold costs and acquisitions) for such period as a percentage of Adjusted EBITDAX for the same period. We use this metric to evaluate from period to period the efficient use of our upstream capital expenditures to maintain or grow our upstream production. We target an Upstream Reinvestment Rate of 50% or less to allow for funding of strategic initiatives. In addition, we target a Maintenance Reinvestment Rate of less than 45%. For a reconciliation of upstream capital expenditures (accrued) to cash flows used in development of natural gas properties in the consolidated statements of cash flows, see "*— Liquidity and Capital Resources — Capital Resources — Cash flows used in investing activities*."

Adjusted Free Cash Flow. We define Adjusted Free Cash Flow as net cash provided by (used in) operating activities, excluding cash paid for contingent consideration and changes in operating assets and liabilities, less total cash paid for capital expenditures (excluding leasehold costs and acquisitions). Adjusted Free Cash Flow is a supplemental non-GAAP financial measure that is used by our management and other external users of our financial statements, such as industry analysts, investors, lenders, rating agencies and others to assess our ability to internally fund our capital program, service or incur additional debt and to pay dividends. We believe Adjusted Free Cash Flow is a useful liquidity measure because it allows us and others to compare cash flow provided by operating activities across periods and to assess our ability to internally fund our capital program (including acquisitions), to reduce leverage, fund acquisitions and pay dividends to our stockholders. See "*Prospectus Summary — Summary Historical Financial Information — Non-GAAP Financial Measures*" for a description of Adjusted Free Cash Flow and for a reconciliation of Adjusted Free Cash Flow to net loss and net cash provided by (used in) operating activities, its most directly comparable GAAP measures.

Adjusted Free Cash Flow Margin. We define Adjusted Free Cash Flow Margin as the ratio of Adjusted Free Cash Flow for any period to total revenues, excluding derivative gains and losses, for such period. We use this metric to assess our liquidity relative to our revenues. Adjusted Free Cash Flow Margin illustrates the efficiency with which the Company generates Adjusted Free Cash Flow.

Production Volume. Production volume for any period is defined as the volume of natural gas, NGLs or oil we extract from our natural gas properties. We use this metric to monitor the efficiency and effectiveness of our upstream operations.

Total Net Leverage Ratio. Total Net Leverage Ratio is the ratio of our total debt less cash and cash equivalents to Adjusted EBITDAX. We use this metric to evaluate our total debt relative to our ability to generate cash through Adjusted EBITDAX. We target a Total Net Leverage Ratio of 1.0x to 1.5x to ensure adequate liquidity to meet debt obligations and a low debt burden to protect Adjusted Free Cash Flow. This metric also provides management with a benchmark of debt levels while considering growth opportunities and our ability to manage periods of commodity price volatility.

Factors that Affect Comparability of Our Results of Operations

Our historical financial condition and results of operations for the periods presented may not be comparable, either from period to period or going forward primarily for the following reasons:

Acquisitions. We intend to continue to grow our operations and financial results through strategic acquisitions like the Devon Barnett Acquisition and the Exxon Barnett Acquisition. Additionally, we may from time to time effect divestitures of certain of our non-core assets. As a result of our Devon Barnett Acquisition, the 2021 acquisition of Temple I and the 2023 acquisition of Temple II by the BKV-BPP Power Joint Venture, as well as our Exxon Barnett Acquisition, our historical reserves, operating and financial data may not be comparable from period to period. For example, our average daily production volumes of natural gas, NGLs, and oil was 807.6 MMcfe/d and 878.2 MMcfe/d for the six months ended June 30, 2024 and 2023, respectively, and 859.7 MMcfe/d, 765.9 MMcfe/d, and 673.3 MMcfe/d for the years ended December 31, 2023, 2022, and 2021, respectively. In addition, our losses from the BKV-BPP Power Joint Venture were $23.0 million and $14.3 million for the six months ended June 30, 2024 and 2023, and for the years ended December 31, 2023, 2022, and 2021, earnings from the BKV-BPP Power Joint Venture were $16.9 million, $8.5 million and $0.9 million, respectively.

Supply, demand, market risk and the impact on natural gas, NGLs and oil prices. As discussed above in "*— Market Outlook*," the natural gas and oil industry historically has been cyclical with highly volatile commodity prices, which trended lower during 2023 and into the first half of 2024. Natural gas and oil prices are subject to large fluctuations in response to relatively minor changes in the demand for natural gas, NGLs and oil. Prices are affected by current and expected supply and demand dynamics, including the level of drilling, completion, and production activities by other natural gas production companies, global industry-wide supply chain disruptions, widespread shortages of labor, material, and services, the ability to agree and maintain production levels by members of OPEC and other oil producing countries, and political instability of other energy producing countries, resulting in increased supply in the global market. Other factors impacting supply and demand include weather conditions (including severe weather events), pipeline capacity constraints, inventory storage levels, basis differentials, export capacity, supply chain quality and availability, strength of the U.S. dollar as well as other factors, the majority of which are outside of our control. Due to the impacts on commodity prices, they are likely to remain volatile in the future, but in the near-term, they may continue to trend on average between $1.50 to $2.00 and we believe our 2024 budget reflects this trend.

For example, due to the volatility in commodity prices, for the six months ended June 30, 2024, our average realized product prices were $1.82 compared to $2.22 for the six months ended June 30, 2023. For the years ended December 31, 2023, 2022, and 2021, our average realized product prices were $2.25, $5.84, and $3.38, respectively. Taking into consideration production volumes, production revenues were $267.5 million and $352.9 million for the six months ended June 30, 2024 and 2023, respectively, and $706.2 million, $1.6 billion, and $829.7 million for the years ended December 31, 2023, 2022, 2021, respectively.

Public company expenses. We expect to incur incremental, non-recurring costs related to our transition to a publicly traded company, including the costs of this initial public offering and the costs associated with the initial implementation of our Sarbanes-Oxley Section 404 internal control implementation and testing. We also expect to incur additional significant and recurring expenses as a publicly traded corporation, including costs associated with the employment of additional personnel, compliance under the Exchange Act, annual and quarterly reports to common stockholders, registrar and transfer agent fees, national stock exchange fees, audit fees, legal fees, incremental director and officer liability insurance costs and director and officer compensation.

Winter Storm Uri. Our marketing revenues consist of our portion of net profits earned through an agreement we have in place with a third party who operates a commodity trading book. In 2021, we received higher than normal marketing revenues due to the pricing volatility surrounding abnormal weather events. Although the agreement remains in effect, we consider such levels of marketing revenues to be unusual and may not recur in future periods.

Factors that Significantly Affect Our Financial Condition and Results of Operations

We derive almost all of our revenues from the sale of natural gas and NGLs produced from our interests in properties located in the Barnett and NEPA and through gathering, processing and transporting natural gas. Our revenues, cash flows from operations and future growth depend substantially on factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. Natural gas and NGL prices have historically been volatile and may continue to fluctuate widely in the future due to a variety of factors, including, but not limited to, severe weather, natural gas storage levels, prevailing economic conditions, supply and demand of hydrocarbons or other energy sources in the marketplace and geopolitical events such as wars, international relations, or political leadership. Sustained periods of low natural gas prices could materially and adversely affect our financial condition, our results of operations, the quantities of natural gas and NGLs that we can economically produce and our ability to access capital.

We utilize derivative contracts in connection with our natural gas operations to provide an economic hedge of our exposure to commodity price risk associated with anticipated future natural gas and NGL production. The derivative contracts we enter into consist of swaps, producer collars, call options and basis swaps, subject to master netting agreements with each individual counterparty. While these arrangements are structured to reduce our exposure to commodity price decreases, they can also limit the benefit we might otherwise receive from commodity price increases. For example, for the six months ended June 30, 2024 and 2023, we had net realized and unrealized derivative losses of $11.2 million and net realized and unrealized derivative gains of $116.9 million, respectively, and for the years ended December 31, 2023, 2022 and 2021, we had net realized and unrealized derivative gains of $238.7 million and net realized and unrealized derivative losses of $629.7 million and $383.8 million, respectively. We elected not to designate our current portfolio of commodity derivative contracts as hedges for accounting purposes. Therefore, changes in fair value of these derivative instruments are recognized in earnings. See "— *Quantitative and Qualitative Disclosures About Market Risk — Commodity Price Risk and Hedging Activities*" for additional discussion of our commodity derivative contracts. Our results of operations, liquidity and financial condition would be negatively impacted if natural gas prices were to become depressed or decline materially from current levels, or there is otherwise an unexpected material impact on commodity prices, and we have experienced variance in our results of operations and financial condition due to our hedging transactions.

Businesses engaged in the exploration and production of natural gas and NGLs, such as ours, face the challenge of natural production declines. As initial reservoir pressures are depleted, natural gas and NGL production from a given well naturally decreases. Thus, as does any natural gas exploration and production company, we deplete part of our asset base with each unit of natural gas and NGLs we produce. We attempt to overcome this natural decline by drilling and refracturing to unlock additional reserves and acquiring more reserves than we produce. Our future growth will depend on our ability to enhance production levels from our existing reserves and to continue to add reserves in excess of production in a cost-effective manner, through development of existing assets and acquisitions. Our ability to make capital expenditures to increase production from our existing reserves and to add reserves through drilling is dependent on our capital resources and can be limited by many factors, including our ability to access capital in a cost-effective manner and to timely obtain drilling permits and regulatory approvals.

Other factors significantly affecting our financial condition and results of operations include, among others:

- success in drilling new wells;
- the availability of attractive acquisition opportunities and our ability to execute them;
- the amount of capital we invest in the leasing and development of our properties;
- facility or equipment availability and unexpected downtime; and
- delays imposed by or resulting from compliance with regulatory requirements.

Sources of Revenues

Currently, substantially all of our revenues are derived from the sale of our natural gas production and the NGLs that are extracted from processing our natural gas, though we also generate a portion of our revenues from the sale of crude oil, midstream and surface operations, a minority equity interest in a midstream system and certain marketing revenue and other income. Our midstream and surface operations primarily support our own exploration and production operations, with revenues generated primarily from fees charged for midstream and surface services, including transportation, freshwater sourcing and disposal and other services to us and our affiliates and, to a lesser extent, third parties.

We sell natural gas, NGLs and oil at specific delivery points. To deliver our products, we may incur third party fees for gathering and transportation. Fees incurred prior to transfer of control are recorded as gathering and transportation expenses. Fees incurred after transfer of control are recognized as a reduction to our transaction price. Pricing of commodities is subject to supply and demand as well as to seasonal, political and other conditions that we generally cannot control. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

Natural gas, NGL and oil sale revenues

Approximately 89.4% and 95.5% of our total revenues, excluding net derivative gains (losses) for the six months ended June 30, 2024 and 2023, respectively, were derived through the production and sale of natural gas, NGLs, and oil. Approximately 95.5%, 98.4% and 93.3% of our total revenues, excluding net derivative gains (losses), for the years ended December 31, 2023, 2022 and 2021, respectively, were derived through the production and sale of natural gas, NGLs and oil. Production of these resources occurs exclusively within the Barnett and NEPA. The following table presents the breakdown of our revenues from the production and sale of natural gas, NGLs and oil for the periods presented:

	Six Months Ended June 30,		Year Ended December 31,		
	2024	2023	2023	2022	2021
Natural gas sales	67%	74%	72%	80%	72%
NGL sales	32%	26%	27%	19%	27%
Oil sales	1%	1%	1%	1%	1%

Our revenues are influenced by production volumes as well as commodity prices. The following table presents our historical production volumes for the periods presented:

	Six Months Ended June 30,		Year Ended December 31,		
Production Data	**2024**	**2023**	**2023**	**2022**	**2021**
Natural gas (MMcf)	116,756	126,898	249,766	217,585	186,055
NGLs (MBbls)	4,987	5,280	10,554	10,187	9,829
Oil (MBbls)	52	63	119	140	123
Total volumes (MMcfe)	146,990	158,956	313,804	279,547	245,767
Average daily total volumes (MMcfe/d)	807.6	878.2	859.7	765.9	673.3

Midstream revenues

Approximately 2.5% and 2.3% of our total revenues, excluding net derivative gains (losses), for the six months ended June 30, 2024 and 2023, respectively, were generated from our midstream operations, including our approximate 29.4% non-operated interest in a midstream system operated by Repsol (our “Repsol Midstream Interest”). On June 14, 2024, we sold our Repsol Midstream Interest in connection with the sale of BKV Chaffee. For the years ended December 31, 2023, 2022, and 2021, these midstream revenues were approximately 2.2%, 0.8%, and 0.7% of our total revenues, excluding net derivative gains (losses), respectively. For the year ended December 31, 2021, midstream revenues were generated exclusively from our Repsol Midstream Interest. For the six months ended June 30, 2024 and 2023, and for the years ended December 31, 2023 and 2022, in addition to revenues from our Repsol Midstream Interest, we began to generate midstream revenues from midstream assets acquired in the Exxon Barnett Acquisition, which we operate. Revenues from the non-operated Repsol Midstream Interest and our operated midstream assets are recognized when services are rendered based on quantities transported and measured according to the underlying contracts.

Marketing revenues

Approximately 2.3% and 1.3% of our total revenues, excluding net derivative gains (losses) for the six months ended June 30, 2024 and 2023, respectively, and 1.2%, 0.7%, and 5.9% of our total revenues, excluding net derivative gains (losses) for the years ended December 31, 2023, 2022, and 2021, respectively, consists of our portion of net profits earned through an agreement with Concord Energy, LLC, the third-party marketer of substantially all of our natural gas production. Pursuant to such agreement, which we entered into in 2021, we receive a fixed percentage of all net income realized in the resale of our and other producers’ hydrocarbons. In February 2021, we received higher than normal marketing revenues due to the pricing volatility surrounding the events of Winter Storm Uri. Although the agreement remains in effect, we consider such levels of marketing revenues to be unusual and may not recur in future periods.

Realized Commodity Prices

Our results of operations are heavily influenced by commodity prices. Natural gas, NGL and oil prices have historically been volatile and decreased significantly in early 2023 and again in the first half of 2024 and are considerably lower than the near-record high prices experienced in 2022. For example, the average NYMEX Henry Hub monthly settlement pricing was $2.07 per MMBtu compared to $2.76 per MMBtu for the six months ended June 30, 2024 and 2023, respectively, and $2.74, $6.64, and $3.84 for the years ended

December 31, 2023, 2022, and 2021, respectively. A future decline in commodity prices may adversely affect our business, financial condition, and results of operations. Lower commodity prices may not only decrease our revenues, but also the amount of natural gas and oil that we can produce economically.

NYMEX Henry Hub, for gas prices, and NYMEX WTI, for oil prices, are widely used benchmarks for the pricing of natural gas and oil in the United States. The price we receive for our natural gas and oil production is generally different than the NYMEX price because of adjustments for delivery location ("basis"), relative quality and other factors. As such, our revenues are sensitive to the price of the underlying commodity to which they relate. The following is a comparison of average pricing excluding and including the effects of derivatives:

	Six Months Ended June 30,		Year Ended December 31,		
	2024	2023	2023	2022	2021
Average prices:					
Natural gas (Mcf):					
Average NYMEX Henry Hub price	$ 2.07	$ 2.76	$ 2.74	$ 6.64	$ 3.84
Average natural gas realized price (excluding derivatives)	$ 1.53	$ 2.03	$ 2.04	$ 6.02	$ 3.21
Average natural gas realized price (including derivatives)(1)	$ 1.99	$ 2.29	$ 2.23	$ 3.72	$ 2.29
Differential to NYMEX Henry Hub	$ (0.54)	$ (0.73)	$ (0.70)	$ (0.62)	$ (0.63)
NGLs (Bbl):					
Average NYMEX WTI price	$ 79.69	$ 74.73	$ 77.58	$ 95.03	$ 67.92
Average NGL realized price (excluding derivatives)	$ 16.97	$ 17.32	$ 17.80	$ 30.58	$ 22.90
Average NGL realized price (including derivatives)(1)	$ 17.21	$ 16.98	$ 17.55	$ 27.78	$ 16.03
Differential to NYMEX WTI	$(62.72)	$(57.41)	$(59.78)	$ (64.45)	$(45.02)
Oil (Bbl):					
Average NYMEX WTI price	$ 79.69	$ 74.73	$ 77.58	$ 95.03	$ 67.92
Average oil realized price (excluding derivatives)	$ 71.81	$ 69.71	$ 70.97	$ 84.76	$ 61.46
Average oil realized price (including derivatives)(1)	$ 71.81	$ 69.71	$ 70.97	$ 84.76	$ 61.46
Differential to NYMEX WTI	$ (7.88)	$ (5.02)	$ (6.61)	$ (10.27)	$ (6.46)
High and low NYMEX prices:					
Oil (Bbl):					
High	$ 87.69	$ 83.26	$ 93.67	$123.64	$ 84.65
Low	$ 70.62	$ 66.61	$ 66.61	$ 71.05	$ 47.62
Natural gas (Mcf):					
High	$ 13.20	$ 3.78	$ 3.78	$ 9.85	$ 23.86
Low	$ 1.25	$ 1.74	$ 1.74	$ 3.46	$ 2.43

(1) Impact of derivatives prices excludes $13.3 million, $39.1 million, and $46.7 million of gains on derivative contract terminations for the six months ended June 30, 2024 and 2023 and for the year ended December 31, 2023, respectively, and $158.4 million and $30.9 million of losses on derivative contract terminations for the years ended December 31, 2022 and 2021, respectively.

Commodity Price Risk and Derivatives and Hedging Activities

The volatility of energy markets makes it extremely difficult to predict future natural gas, NGL and oil price movements with any certainty, and our results of operations and cash flows are impacted by changes in market prices for natural gas, NGLs and oil. Lower natural gas, NGL and oil prices may reduce the amount of natural gas and oil that we can produce economically. This may also result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs or if our production estimates change or our exploration or development activities are curtailed, successful efforts accounting rules may require us to recognize impairment expense as a non-cash charge to earnings, and to the carrying value of our natural gas properties.

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in commodity prices, from time to time we enter into derivative arrangements for our production. In most of our current positions, our hedging activity may also reduce our ability to benefit from increases in commodity prices. We will sustain losses to the extent our derivatives contract prices are lower than market prices, and conversely, we will recognize gains to the extent our derivatives contract prices are higher than market prices. The price we receive for sales of our natural gas, NGLs and oil is generally less than the NYMEX prices because of adjustments for basis, relative quality and other factors.

During the six months ended June 30, 2024, our derivative settlements increased our natural gas revenue by $53.4 million and increased our NGL revenue by $1.2 million, and early terminations of natural gas derivative contracts during this period increased revenue by an additional $13.3 million. During the six months ended June 30, 2023, our derivative settlements increased our natural gas revenue by $33.4 million and decreased our NGL revenue by $1.8 million, and early terminations of our derivative contracts during this period increased revenue by an additional $39.1 million. During the year ended December 31, 2023, our derivative settlements increased our natural gas revenue by $46.1 million and decreased our NGL revenue by $2.6 million, and early terminations of our natural gas derivative contracts during this period increased revenue by an additional $46.7 million. During the year ended December 31, 2022, our derivative settlements decreased our natural gas revenue by $501.7 million and decreased our NGL revenue by $28.5 million, and early terminations of natural gas derivative contracts during the year ended December 31, 2022 decreased revenue by an additional $158.4 million. During the year ended December 31, 2021, our derivative settlements decreased our natural gas revenue by $170.2 million and decreased our NGL revenue by $67.6 million, and early terminations of natural gas derivative contracts during the year ended December 31, 2021 decreased revenue by an additional $30.9 million.

The following table summarizes our outstanding natural gas commodity derivatives indexed to NYMEX Henry Hub pricing as of June 30, 2024. Prices to be realized for hedged production will be less than these NYMEX prices because of location, quality and other adjustments.

Instrument	MMBtu	Weighted Average Price (USD)	Weighted Average Price Floor	Weighted Average Price Ceiling	Fair Value as of June 30, 2024 (in thousands)
2024					
Swap	45,517,500	$ 3.52			$ 27,577
2025					
Swap	60,800,000	$ 3.53			$ 3,699
Collars	14,600,000		$ 3.71	$ 4.11	$ 4,994
2026					
Swap	8,550,000	$ 3.53			$ (4,308)
Collars	25,550,000		$ 3.67	$ 4.19	$ 2,171
Call options	36,500,000			$ 5.00	$ (13,041)
2027					
Call options	36,500,000			$ 5.00	$ (14,306)

The following table represents natural gas basis derivatives based on the applicable basis reference price listed below:

Instrument	Basis Reference Price	MMBtu	Weighted Average Basis Differential	Fair Value as of June 30, 2024 (in thousands)
2024				
Swap	NGPL TXOK Basis	12,300,000	$ (0.54)	$ (1,009)
Swap	Transco Leidy Basis	16,560,000	$ (0.89)	$ 1,554

The following table represents natural gas liquids commodity derivatives for contracts, by contract type, expiring through March 31, 2026 based on the applicable index listed below:

Instrument	Commodity Reference Price	Gallons	Weighted Average Price (USD)	Fair Value as of June 30, 2024 (in thousands)
2024				
Swap	OPIS Purity Ethane Mont Belvieu	96,600,000	$ 0.23	$ 3,296
Swap	OPIS IsoButane Mont Belvieu Non-TET	6,568,800	$ 0.93	$ (1,137)
Swap	OPIS Normal Butane Mont Belvieu Non-TET	9,660,000	$ 0.90	$ (1,023)
Swap	OPIS Propane Mont Belvieu Non-TET	36,708,000	$ 0.80	$ (2,059)
Swap	OPIS Natural Gasoline Mont Belvieu Non-TET	15,456,000	$ 1.47	$ (1,552)
2025				
Swap	OPIS Purity Ethane Mont Belvieu	92,767,500	$ 0.25	$ (67)
Swap	OPIS IsoButane Mont Belvieu Non-TET	6,599,250	$ 0.87	$ (644)
Swap	OPIS Normal Butane Mont Belvieu Non-TET	9,082,500	$ 0.84	$ (629)
Swap	OPIS Propane Mont Belvieu Non-TET	35,385,000	$ 0.74	$ (1,539)
Swap	OPIS Natural Gasoline Mont Belvieu Non-TET	13,387,500	$ 1.39	$ (1,552)
2026				
Swap	OPIS Purity Ethane Mont Belvieu	6,615,000	$ 0.25	$ (218)
Swap	OPIS IsoButane Mont Belvieu Non-TET	472,500	$ 0.83	$ (33)
Swap	OPIS Normal Butane Mont Belvieu Non-TET	472,500	$ 0.80	$ (31)
Swap	OPIS Propane Mont Belvieu Non-TET	2,835,000	$ 0.69	$ (163)
Swap	OPIS Natural Gasoline Mont Belvieu Non-TET	945,000	$ 1.40	$ (35)

Principal Components of Cost Structure

Lease operating and workover

Lease operating and workover expenses reflect the costs incurred to maintain our production. Lease operating expenses represent the costs incurred for field employee salaries, saltwater disposal, repairs and maintenance, and other standard operating expenses. Workover expenses include those costs incurred to perform more substantial maintenance or remedial treatments on a well to restore or enhance production. Cost levels for certain of these expenses vary based on the volume of production, among other factors.

Taxes other than income

Taxes other than income consist of production taxes, severance taxes, impact fees and ad valorem taxes. Production and severance taxes are paid on produced natural gas and oil based on a percentage of the market value or sales prices of the natural gas and oil or at fixed per-unit rates established by state authorities. Impact fees are based on drilling activities and natural gas market prices. We pay ad valorem taxes based on the value of our reserves as well as the value of property and equipment.

Gathering and transportation

Gathering and transportation expenses are incurred in connection with the natural gas, NGL and oil gathering and transportation contracts we enter into with third parties and certain of our wholly owned subsidiaries. Pursuant to these contracts, third parties agree to deliver the natural gas, NGLs and oil we produce to our customers for a fee. The fees incurred prior to control transfer are classified as gathering and transportation expenses on the condensed consolidated statements of operations, whereas any fees incurred after transfer of control are included as a reduction of the associated revenues.

Depreciation, depletion, amortization and accretion

Depreciation, depletion and amortization reflect the systematic expensing of the costs capitalized in connection with our costs to acquire, explore and develop natural gas, NGLs and oil. We use the successful efforts method of accounting for natural gas producing activities. Accordingly, we capitalize all costs associated with our acquisition, drilling, development, and retirement efforts and all successful exploration efforts and allocate these costs using the units of production method. Depreciation of midstream assets and other property and equipment is computed over an asset's estimated useful life using a straight-line basis.

Accretion of asset retirement obligations reflects the expense related to the accretion of our asset retirement obligations. Our obligations are accreted using the interest method over the period from initial measurement to the expected timing of settlement and are measured using our credit-adjusted risk-free rate applied when the liability was initially measured.

For any contract deemed to include a leased asset, such as compressors and other equipment used in our upstream operations, that asset is capitalized on the balance sheet as a right-of-use ("ROU") asset and a corresponding lease liability is recorded at the present value of the known future minimum payments of the contract using a discount rate on the date of commencement. Accretion of lease liabilities reflects the periodic accretion expense associated with the increase in the present value of the lease liability over the life of the underlying lease.

Included in depreciation, depletion, amortization and accretion, exploration costs are costs related to unsuccessful leasing efforts, as well as geological and geophysical costs, including seismic costs, costs of unsuccessful exploratory dry holes and costs of other exploratory activities. Impairment costs include impairment and costs associated with leases expirations, impairment of design and initial costs related to pads that are no longer planned to be placed into service and impairment of proved properties due to lower future commodity prices. We charge impairment expense for expired or soon-to-be expired leases when we determine they are impaired based on factors such as remaining lease terms, reservoir performance, commodity price outlooks and future plans to develop the acreage. We also record impairment charges for proved properties on a geological reservoir basis when events or changes in circumstances indicate that a property's carrying amount may not be recoverable.

General and administrative

General and administrative expenses typically represent costs for payroll and benefits for our work force, equity-based compensation expense, integration support, consulting fees, costs incurred to maintain our headquarters, and costs incurred for various legal proceedings which arise through the normal course of business, among others.

Gains (losses) on contingent consideration liabilities

Pursuant to the separate purchase agreements associated with the Devon Barnett Acquisition and the Exxon Barnett Acquisition, we agreed to earnout obligations pursuant to which we agreed to make certain contingent consideration payments based on future prices of natural gas. As of June 30, 2024, we paid Devon Energy a total of $150.0 million in contingent consideration payments. We have not paid any contingent consideration payments to Exxon Mobil Corporation as of June 30, 2024. These unpaid future contingent consideration payments are stated at fair value on our condensed consolidated balance sheets, with changes in fair value recorded in the condensed consolidated statements of operations.

Interest expense and related party interest expense

We finance a portion of our capital expenditures, working capital requirements and acquisitions with borrowings under the RBL Credit Agreement. As a result, we incur interest expense that is affected by both fluctuations in interest rates under our credit facility and our financing decisions. We have not historically utilized interest rate swaps to mitigate fluctuations in interest rates.

Income tax benefit (expense)

We are subject to state and U.S. federal income taxes. The difference between our financial statement income tax expense and our U.S. federal income tax liability is primarily due to the differences in the tax and financial statement treatment of natural gas properties and the deferral of unsettled commodity derivative gains and losses for tax purposes until they are settled. We also pay certain state income or franchise taxes where state income or franchise taxes are determined on a basis other than income. We record deferred income tax expense to the extent our deferred tax liabilities exceed our deferred tax assets.

In the future, we expect we will be able to realize an additional income tax benefit from Section 45Q tax credits. For facilities placed in service on or after February 9, 2018 and before January 1, 2023, Section 45Q of the Code generally provides the capturing parties a tax credit that escalates until 2026, when it reaches $50 per ton for CO_2 directly stored in geologic formations, annually escalating for inflation thereafter. For facilities placed in service after December 31, 2022, the credit amount increased to $85 per ton, subject to satisfaction or non-application of certain prevailing wage and apprenticeship requirements (or $17 per ton if such prevailing wage and apprenticeship requirements are not satisfied), with adjustments for inflation after 2026. In either case, the Section 45Q tax credits are available for a 12-year period for qualifying facilities that begin construction before January 1, 2033.

Results of Operations

The following tables present selected financial and operating information for the periods presented:

(in thousands)	Six Months Ended June 30, 2024	Six Months Ended June 30, 2023
Revenues and other operating income		
Natural gas revenues	$ 179,175	$ 257,032
NGL revenues	84,632	91,477
Oil revenues	3,734	4,398
Midstream revenues	7,506	8,428
Derivative gains (losses), net	(11,165)	116,947
Marketing revenues	6,967	4,732
Gain on sales of assets	6,784	339
Related party and other	10,479	3,314
Total revenues and other operating income	288,112	486,667
Operating expenses		
Lease operating and workover	68,640	80,723
Taxes other than income	21,215	41,496
Gathering and transportation	113,105	120,586
Depreciation, depletion, amortization and accretion	111,479	78,354
General and administrative	39,941	52,488
Other	11,276	8,483
Total operating expenses	365,656	382,130
Income (loss) from operations	(77,544)	104,537
Other income (expense)		
Gains on contingent consideration liabilities	6,070	22,910
Losses from equity affiliate	(22,960)	(14,275)
Loss on early extinguishment of debt	(13,877)	—
Interest income	3,404	1,136
Interest expense	(31,246)	(34,377)
Interest expense, related party	(3,852)	(3,083)
Other income	350	1,851
Income (loss) before income taxes	(139,655)	78,699
Income tax benefit (expense)	41,373	(17,885)
Net income (loss)	$ (98,282)	$ 60,814

(in thousands)	Year Ended December 31, 2023	2022	2021
Revenues and other operating income			
Natural gas revenues	$509,846	$1,310,339	$ 597,050
NGL revenues	187,860	311,542	225,135
Oil revenues	8,445	11,866	7,560
Midstream revenues	16,168	12,676	6,917
Derivative gains (losses), net	238,743	(629,701)	(383,847)
Marketing revenues	8,710	11,001	52,616
Related party and other	8,251	2,799	251
Total revenues and other operating income	978,023	1,030,522	505,682
Operating expenses			
Lease operating and workover	150,647	131,497	86,831
Taxes other than income	72,290	114,668	45,650
Gathering and transportation	248,990	208,758	173,587
Depreciation, depletion, amortization and accretion	223,370	118,909	92,277
General and administrative	114,688	148,559	85,740
Other	12,625	3,567	1,274
Total operating expenses	822,610	725,958	485,359
Income from operations	155,413	304,564	20,323
Other income (expense)			
Bargain purchase gain	—	170,853	—
Gain on settlement of litigation	—	16,866	—
Gains (losses) on contingent consideration liabilities	38,375	6,632	(194,968)
Earnings from equity affiliate	16,865	8,493	910
Interest income	3,138	1,143	8
Interest expense	(69,942)	(26,322)	—
Interest expense, related party	(7,078)	(10,846)	(2,134)
Other income	8,372	1,411	872
Income (loss) before income taxes	145,143	472,794	(174,989)
Income tax benefit (expense)	(28,225)	(62,652)	40,526
Net income (loss) attributable to BKV Corporation	$116,918	$ 410,142	$(134,463)
Less accretion of preferred stock to redemption value	—	—	(3,745)
Less preferred stock dividends	—	—	(9,900)
Less deemed dividend on redemption of preferred stock	—	—	(22,606)
Net income (loss) attributable to common stockholders	$116,918	$ 410,142	$(170,714)

Comparison of the Six Months Ended June 30, 2024 and 2023

Operating revenues

Our operating revenues include revenues from the sale of natural gas, NGLs, and oil, midstream revenues, gains and losses on our derivative contracts, marketing revenues, and other revenues. The following table provides information on our revenues for the periods presented:

	Six Months Ended June 30,			
(in thousands, other than percentages)	**2024**	**2023**	**$ Change**	**% Change**
Revenues				
Natural gas revenues	$ 179,175	$ 257,032	$ (77,857)	(30)%
NGL revenues	84,632	91,477	(6,845)	(7)%
Oil revenues	3,734	4,398	(664)	(15)%
Midstream revenues	7,506	8,428	(922)	(11)%
Derivative gains (losses), net	(11,165)	116,947	(128,112)	*
Marketing revenues	6,967	4,732	2,235	47%
Gain on sales of assets	6,784	339	6,445	*
Related party and other	10,479	3,314	7,165	*
Total revenues and other operating income	$ 288,112	$ 486,667		

* *Percentage not meaningful*

Natural gas revenues

Our natural gas revenues decreased by approximately $77.9 million, or 30%, to $179.2 million for the six months ended June 30, 2024, from $257.0 million for the six months ended June 30, 2023. The impact of commodity price decreases, excluding the effect of derivative settlements, provided a $57.3 million decrease in period-over-period revenues (calculated as the change in the period-to-period average price times current period production volumes). The decrease was also due to lower production volumes during the six months ended June 30, 2024, which accounted for a $20.6 million decrease in period-over-period revenues (calculated as the change in period-to-period volumes times the prior period average price).

NGL revenues

Our NGL revenues decreased by approximately $6.9 million, or 7%, to $84.6 million for the six months ended June 30, 2024, from $91.5 million for the six months ended June 30, 2023. The decrease was due to lower production volumes during the six months ended June 30, 2024, which provided a $5.1 million decrease in period-over-period revenues (calculated as the change in period-to-period volumes times the prior period average price). The impact of commodity price decreases, excluding the effect of derivative settlements, accounted for a $1.8 million decrease in period-over-period revenues (calculated as the change in the period-to-period average price times current period production volumes).

Oil revenues

Our oil revenues decreased by approximately $0.7 million, or 15%, to $3.7 million for the six months ended June 30, 2024 from $4.4 million for the six months ended June 30, 2023. Lower production volumes during the six months ended June 30, 2024 accounted for a $0.8 million decrease in period-over-period revenues (calculated as the change in period-to-period volumes times the prior period average price). This decrease was offset by the impact of commodity price increases, excluding the effect of derivative settlements, which provided a $0.1 million increase in period-over-period revenues (calculated as the change in the period-to-period average price times current period production volumes).

Midstream revenues

Our midstream revenues decreased by approximately $0.9 million, or 11%, to $7.5 million for the six months ended June 30, 2024 from $8.4 million for the six months ended June 30, 2023. This decrease was primarily due to changes in deal structures that reduced midstream transportation revenue while increasing third party gas sales.

Derivative gains (losses), net

For the six months ended June 30, 2024, we had net realized and unrealized losses on derivative contracts of $11.2 million compared to net realized and unrealized gains on derivative contracts of $116.9 million for the six months ended June 30, 2023. The increased losses for the six months ended June 30, 2024 was primarily attributable to the unrealized loss on the call option we sold in January 2024, which limits our 2025/2026 pricing upside, and is currently in a long term liability position. In addition, due to the significant decrease in the forward curve for natural gas prices during the six months ended June 30, 2023, the fair value change in our open derivatives was in more of an unrealized gain position for the six months ended June 30, 2023 compared to the six months ended June 30, 2024.

Marketing revenues

Our marketing revenues increased by approximately $2.3 million, or 47%, to $7.0 million for the six months ended June 30, 2024 from $4.7 million for the six months ended June 30, 2023. Our marketing revenues are derived under our marketing agreement with a third party pursuant to which we receive a fixed percentage of all net income realized in the resale of our and other producers' hydrocarbons. The increase in marketing revenues during the six months ended June 30, 2024 compared to the six months ended June 30, 2023 was primarily due to colder than normal weather in NEPA in the month of January 2024.

Gain on sale of assets

For the six months ended June 30, 2024, we had a net gain on sales of assets of $6.8 million. This was primarily due to the sale of our wholly owned subsidiary, BKV Chaffee, for $103.2 million, net of third party transaction costs. The assets sold had an approximate carrying value of $97.4 million. The remaining net gain on sales of assets of $1.1 million was due to the gain on sales of other property and equipment during the six months ended June 30, 2024.

Related party and other

We generate a portion of our revenues from a management fee from the BKV-BPP Power Joint Venture, the sale of third-party natural gas, and CCUS revenues generated from Section 45Q tax credits. Our related party and other revenues were $10.5 million for the six months ended June 30, 2024, as compared to $3.3 million for the six months ended June 30, 2023. Other revenues increased during the six months ended June 30, 2024 compared to the six months ended June 30, 2023 primarily due to 45Q tax credits of $6.0 million from the injection of CO_2 in our Barnett Zero well, which started in the fourth quarter of 2023, as well as an increase in operating fee income of $0.9 million due to contracted rate increases.

Operating Expenses

Our operating expenses reflect costs incurred in the development, production and sale of natural gas, NGLs, and oil. The following table provides information on our operating expenses:

(in thousands, other than percentages and average costs)	Six Months Ended June 30, 2024	2023	$ Change	% Change
Operating expenses				
Lease operating and workover	$ 68,640	$ 80,723	$(12,083)	(15)%
Taxes other than income	21,215	41,496	(20,281)	(49)%
Gathering and transportation	113,105	120,586	(7,481)	(6)%
Depreciation, depletion, amortization and accretion	111,479	78,354	33,125	42%
General and administrative	39,941	52,488	(12,547)	(24)%
Other	11,276	8,483	2,793	33%
Total operating expenses	$ 365,656	$ 382,130		
Average costs per Mcfe				
Lease operating and workover	$ 0.46	$ 0.51	$ (0.05)	(10)%
Taxes other than income	0.14	0.26	(0.12)	(46)%
Gathering and transportation	0.77	0.76	0.01	1%
Depreciation, depletion, amortization and accretion	0.76	0.49	0.27	55%
General and administrative	0.27	0.33	(0.06)	(18)%
Other	0.08	0.05	0.03	60%
Total	$ 2.48	$ 2.40		

* *Percentage not meaningful*

Lease operating and workover

The following table summarizes our components of lease operating expenses for the periods presented:

	Six Months Ended June 30,					
	2024		2023		$ Change	% Change
(in thousands, other than percentages and average costs)	Amount	Per Mcfe	Amount	Per Mcfe		
Lease operating expenses	$65,351	$ 0.44	$76,040	$ 0.48	$(10,689)	(14)%
Workover expense	3,289	0.02	4,683	0.03	(1,394)	(30)%
Total lease operating and workover expense	$68,640	$ 0.46	$80,723	$ 0.51	$(12,083)	(15)%

* *Percentage not meaningful*

Lease operating and workover expenses were $68.6 million, or $0.46 per Mcfe, for the six months ended June 30, 2024, which was a decrease of approximately $12.1 million, or 15%, from $80.7 million, or $0.51 per Mcfe, for the six months ended June 30, 2023. The decrease in lease operating and workover expenses during the six months ended June 30, 2024 compared to the same period in 2023 was due to decreases in repairs and maintenance of $3.3 million, materials and labor of $3.0 million, and compression and water expenses of $2.6 million, all of which were due to cost savings initiatives that began during 2023. In addition, during the six months ended June 30, 2024, we received a credit of $1.5 million for a water sharing agreement that related to 2023. We had other decreases of approximately $1.7 million of individually immaterial net decreases in other lease operating and workover costs in connection with our operations.

Taxes other than income

Taxes other than income were $21.2 million, or $0.14 per Mcfe, for the six months ended June 30, 2024, which was a decrease of approximately $20.3 million, or 49%, from $41.5 million, or $0.26 per Mcfe, for the year ended six months ended June 30, 2023. The decrease in taxes other than income during the year ended six months ended June 30, 2024 compared to 2023 was due to decreases in ad valorem and property taxes, and natural gas and NGL production taxes, both associated with our operations in the Barnett of $14.2 million and $6.1 million, respectively. Certain ad valorem and production taxes are not applicable to our NEPA properties.

Gathering and transportation

Gathering and transportation expenses were $113.1 million, or $0.77 per Mcfe, for the six months ended June 30, 2024, which was a decrease of approximately $7.5 million, or 6%, from $120.6 million, or $0.76 per Mcfe, for the six months ended June 30, 2023. This decrease was driven by decreased production in the Barnett and NGL rate decreases of $6.9 million and $5.5 million, respectively. This was offset by natural gas rate increases in the Barnett of $3.8 million, and in 2024 we entered into new contracts where we started incurring gathering costs to commercially sequester the CO_2 waste utilizing our Barnett Zero Project of $0.8 million, and outsourcing gathering costs with our midstream business of $0.4 million.

Depreciation, depletion, amortization, and accretion

Depreciation, depletion, amortization, and accretion was $111.5 million, or $0.76 per Mcfe, for the six months ended June 30, 2024, which was an increase of approximately $33.1 million, or 42%, from $78.4 million, or $0.49 per Mcfe, for the six months ended June 30, 2023. The increase in depreciation, depletion, amortization, and accretion during the six months ended June 30, 2024 compared to the six months ended June 30, 2023 was primarily due to increased development of our natural gas properties in NEPA and the Barnett during 2023.

General and administrative

General and administrative expenses were $39.9 million, or $0.27 per Mcfe, for the six months ended June 30, 2024, which was a decrease of approximately $12.5 million, or 24%, from $52.5 million, or $0.33 per Mcfe, for the six months ended June 30, 2023. The decrease in general and administrative expenses during the six months ended June 30, 2024 compared to the six months ended June 30, 2023 was due to a decrease of $7.1 million in equity-based compensation, employee wages, contract labor and fees, a decrease of $4.0 million of management fees paid to Verde CO2 during the six months ended June 30, 2023. The contract with Verde CO_2 terminated in November 2023. In addition, there was a decrease of $1.3 million in office and facility expenses during the six months ended June 30, 2024 compared to 2023.

Other operating expenses

Other operating expenses were $11.3 million, or $0.08 per Mcfe, for the six months ended June 30, 2024, which was an increase of approximately $2.8 million, or 33%, from $8.5 million, or $0.05 per Mcfe, for the six months ended June 30, 2023. The increase in other operating expenses during the six months ended June 30, 2024 compared to the same period in 2023 was primarily due to costs incurred during the current period related to waste emissions of $5.0 million based on $900/ton of methane taxed over certain thresholds established by the Inflation Reduction Act, $1.8 million in CCUS operating expense, and emissions monitoring costs of $1.2 million. This increase was offset by lower rig termination fees of $2.5 million, lower midstream operating expenses and gas purchases of $1.5 million, and $1.2 million of prior year inventory restocking fees.

Other Income (Expense)

Gains on contingent consideration liabilities. We recognized a gain on contingent consideration liabilities accruing as an earnout obligation under the purchase agreements executed in connection with the Devon Barnett Acquisition and the Exxon Barnett Acquisition. The gain on contingent consideration liabilities was $6.1 million for the six months ended June 30, 2024, which was a decrease of $16.8 million from the $22.9 million gain for the six months ended June 30, 2023. The $6.1 million gain compared to the $22.9 million gain was primarily attributable to the prior period’s gain on contingent consideration liabilities with the Devon Barnett Acquisition of $13.5 million compared to the current period's gain of $3.9 million, as well as the prior period's gain on contingent consideration liabilities with the Exxon Barnett Acquisition of $9.4 million compared to the current period's gain of $2.2 million. There were higher gains in the prior period due to a significant decrease in the forward curve commodity pricing for natural gas (NYMEX) and oil (WTI) assumptions used in the Monte Carlo simulations during the six months ended June 30, 2023 compared to slight decreases during the six months ended June 30, 2024.

Losses from equity affiliate. Losses from our equity affiliate were $23.0 million for the six months ended June 30, 2024, which was a change of $8.7 million, from $14.3 million compared to the same period in 2023. Losses from equity affiliate is related to our investment in and our proportionate share in the income or losses of the BKV-BPP Power Joint Venture. On July 10, 2023, the BKV-BPP Power Joint Venture acquired CXA Temple 2, LLC, the owner of 100% of the interests in Temple II, a combined cycle gas turbine and steam turbine power plant located on the same site as Temple I in the Electric Reliability Council of Texas North Zone in Temple, Texas, for an aggregate purchase price of $460.0 million. The Temple Plants deliver power to customers on the ERCOT power network in Texas.

Interest expense. Interest expense was $31.2 million for the six months ended June 30, 2024, which was a decrease of $3.2 million, from $34.4 million for the six months ended June 30, 2023. The decrease in interest expense during six months ended June 30, 2024 was primarily due to the payment of $114.0 million on the term loans borrowed under our Term Loan Credit Agreement, offset by higher interest rates on our revolving credit facilities during the six months ended June 30, 2024 compared to the six months ended June 20, 2023.

Interest expense, related party. Interest expense from related parties was $3.9 million for the six months ended June 30, 2024, which was an increase of $0.8 million, from $3.1 million for the six months ended June 30, 2023. The increase was due to the increase in interest rates period over period.

Other income. Other income was $0.4 million for the six months ended June 30, 2024, which was a decrease of $1.5 million, from $1.9 million for the six months ended June 30, 2023. The decrease was primarily due to the sale of surface rights of $1.1 million during the six months ended June 30, 2023.

Income tax benefit (expense). For the six months ended June 30, 2024, we had an income tax benefit of $41.4 million, which was a change of $59.3 million, from $17.9 million income tax expense for the six months ended June 30, 2023. The period-over-period change was primarily due to a pre-tax loss for the six months ended June 30, 2024 compared to a pre-tax income for the six months ended June 30, 2023. During the six months ended June 30, 2024, we also benefited from the monetization of certain tax credits under Section 45Q of the Code from the injection of CO_2 waste in the Barnett Zero Project and from Code Section 45I Marginal Well Credit from depletion expense, and by state apportionment changes due to the sale of BKV Chaffee.

Comparison of the Years Ended December 31, 2023 and 2022

Operating revenues

Our operating revenues include revenues from the sale of natural gas, NGLs and oil, midstream revenues, gains and losses on our derivative contracts, marketing revenues, and other revenues. The following table provides information on our revenues for the periods presented:

	Year Ended December 31,			
(in thousands, other than percentages)	**2023**	**2022**	**$ Change**	**% Change**
Revenues				
Natural gas revenues	$509,846	$1,310,339	$(800,493)	(61)%
NGL revenues	187,860	311,542	(123,682)	(40)%
Oil revenues	8,445	11,866	(3,421)	(29)%
Midstream revenues	16,168	12,676	3,492	28%
Derivative gains (losses), net	238,743	(629,701)	868,444	*
Marketing revenues	8,710	11,001	(2,291)	(21)%
Related party and other	8,251	2,799	5,452	*
Total revenues and other operating income	$978,023	$1,030,522		

* *Percentage not meaningful*

Natural gas revenues

Our natural gas revenues decreased by approximately $800.5 million to $509.8 million for the year ended December 31, 2023, from $1.3 billion for the year ended December 31, 2022. The impact of commodity price decreases, excluding the effect of derivative settlements, resulted in a $994.3 million decrease in year-over-year revenues (calculated as the change in the year-to-year average price times current year production volumes). This was offset by higher production volumes, primarily from the 2022 Barnett Assets, during the year ended December 31, 2023, which accounted for a $193.8 million increase in year-over-year revenues (calculated as the change in year-to-year volumes times the prior year average price).

NGL revenues

Our NGL revenues decreased by approximately $123.6 million to $187.9 million for the year ended December 31, 2023, from $311.5 million for the year ended December 31, 2022. The impact of commodity price decreases, excluding the effect of derivative settlements, provided a $134.8 million decrease in year-over-year revenues (calculated as the change in the year-to-year average price times current period production volumes).

This was offset by higher production volumes, primarily from the 2022 Barnett Assets, during the year ended December 31, 2023, which accounted for a $11.2 million increase in year-over-year revenues (calculated as the change in year-to-year volumes times the prior year average price).

Oil revenues

Our oil revenues decreased by approximately $3.5 million to $8.4 million for the year ended December 31, 2023 from $11.9 million for the year ended December 31, 2022. The decrease was driven by lower production volumes during the year ended December 31, 2023, which accounted for a $1.9 million decrease in year-over-year revenues (calculated as the change in year-to-year volumes times the prior year average price). The decrease was also due to the impact of commodity price decreases, excluding the effect of derivative settlements, which resulted in a $1.6 million decrease in year-over-year revenues (calculated as the change in the year-to-year average price times current period production volumes).

Midstream revenues

Our midstream revenues increased by approximately $3.5 million to $16.2 million for the year ended December 31, 2023 from $12.7 million for the year ended December 31, 2022. This increase was primarily due to the midstream assets acquired in the Exxon Barnett Acquisition, slightly offset by decreases in the associated production of natural gas properties that our legacy midstream assets support.

Derivative gains (losses), net

For the year ended December 31, 2023, we had net realized and unrealized gains on derivative contracts of $238.7 million compared to net realized and unrealized losses on derivative contracts of $629.7 million for the year ended December 31, 2022. The increased gain for the year ended December 31, 2023 was attributable to decreases in underlying commodity prices and volatility in energy markets, which resulted in higher realized and unrealized gains on derivative contracts.

Marketing revenues

Our marketing revenues decreased by approximately $2.3 million to $8.7 million for the year ended December 31, 2023 from $11.0 million for the year ended December 31, 2022. Our marketing revenues are derived under our marketing agreement with a third party pursuant to which we receive a fixed percentage of all net income realized in the resale of our and other producers' hydrocarbons. The decrease in marketing revenues was primarily due to lower natural gas prices during the year ended December 31, 2023 compared to the year ended December 31, 2022.

Related party and other

We generate a portion of our revenues from a management fee from the BKV-BPP Power Joint Venture and the sale of third-party natural gas. Our related party and other revenues were $8.3 million for the year ended December 31, 2023, as compared to $2.8 million for the year ended December 31, 2022. Other revenues increased during the year ended December 31, 2023 compared to the year ended December 31, 2022 primarily due to our decision to start selling third party natural gas in 2023, in connection with which we recognized sales of $3.8 million for the year ended December 31, 2023.

Operating Expenses

Our operating expenses reflect costs incurred in the development, production and sale of natural gas, NGLs and oil. The following table provides information on our operating expenses:

(in thousands, other than percentages and average costs)	Year Ended December 31, 2023	Year Ended December 31, 2022	$ Change	% Change
Operating expenses				
Lease operating and workover	$ 150,647	$ 131,497	$ 19,150	15%
Taxes other than income	72,290	114,668	(42,378)	(37)%
Gathering and transportation	248,990	208,758	40,232	19%
Depreciation, depletion, amortization and accretion	223,370	118,909	104,461	88%
General and administrative	114,688	148,559	(33,871)	(23)%
Other	12,625	3,567	9,058	*
Total operating expenses	$ 822,610	$ 725,958		
Average costs per Mcfe				
Lease operating and workover	$ 0.48	$ 0.47	$ 0.01	2%
Taxes other than income	0.23	0.41	(0.18)	(44)%
Gathering and transportation	0.79	0.75	0.04	5%
Depreciation, depletion, amortization and accretion	0.71	0.43	0.28	65%
General and administrative	0.37	0.53	(0.16)	(30)%
Other	0.04	0.01	0.03	*
Total	$ 2.62	$ 2.60		

* *Percentage not meaningful*

Lease operating and workover

The following table summarizes our components of lease operating expenses for the periods presented:

(in thousands, other than percentages and average costs)	2023 Amount	2023 Per Mcfe	2022 Amount	2022 Per Mcfe	$ Change	% Change
Lease operating expenses	$142,911	$ 0.46	123,386	$ 0.44	19,525	16%
Workover expense	7,736	0.02	8,111	0.03	(375)	(5)%
Total lease operating and workover expense	$150,647	$ 0.48	131,497	$ 0.47	19,150	15%

* Percentage not meaningful

Lease operating and workover expenses were $150.6 million, or $0.48 per Mcfe, for the year ended December 31, 2023, which was an increase of $19.1 million, or 15%, from $131.5 million, or $0.47 per Mcfe, for the year ended December 31, 2022. The increase in lease operating and workover expenses during the year ended December 31, 2023 compared to the same period in 2022 was primarily due to the Exxon Barnett Acquisition, which closed on June 30, 2022. The acquired operations drove $23.2 million of incremental lease operating and workover expenses during the year ended December 31, 2023. The remaining $4.1 million of decreased lease operating and workover expenses was driven by a $6.5 million decrease in professional services production and equipment, which was offset in part by $2.4 million of individually immaterial net increases in other direct production costs incurred in connection with our operations.

Taxes other than income

Taxes other than income were $72.3 million, or $0.23 per Mcfe, for the year ended December 31, 2023, which was a decrease of $42.4 million, or 37%, from $114.7 million, or $0.41 per Mcfe, for the year ended December 31, 2022. The decrease in taxes other than income during the year ended December 31, 2023 compared to 2022 was primarily due to decreases in natural gas and NGL production taxes associated with our operations from the 2020 Barnett Assets and the 2022 Barnett Assets of $59.0 million and decreases in property taxes related to our NEPA natural gas properties of $1.7 million, in each case due to lower natural gas prices during the year ended December 31, 2023 compared to the year ended December 31, 2022. This was offset by an increase in ad valorem and property taxes on our 2020 Barnett Assets and 2022 Barnett Assets of $18.5 million. Certain ad valorem and production taxes are not applicable to our NEPA natural gas properties.

Gathering and transportation

Gathering and transportation expenses were $249.0 million, or $0.79 per Mcfe, for the year ended December 31, 2023, which was an increase of $40.2 million, or 19%, from $208.8 million, or $0.75 per Mcfe, for the year ended December 31, 2022. Approximately $30.5 million of the increase was driven by the Exxon Barnett Acquisition. The remainder of the increase in gathering and transportation expenses of $9.7 million during the year ended December 31, 2023 compared to the same period in 2022 was due to an increase in cost and production volumes from the development of the 2020 Barnett Assets.

Depreciation, depletion, amortization and accretion

Depreciation, depletion, amortization and accretion was $223.4 million, or $0.71 per Mcfe, for the year ended December 31, 2023, which was an increase of $104.5 million, or 88%, from $118.9 million, or $0.43 per Mcfe, for the year ended December 31, 2022. The increase in depreciation, depletion, amortization, and accretion during the year ended December 31, 2023 compared to the year ended December 31, 2022 was primarily due to the Exxon Barnett Acquisition, which accounted for an additional $64.9 million of depreciation, depletion, amortization and accretion expense during the year ended December 31, 2023. The remaining increase of $39.6 million was primarily due to increased production from the development of our natural gas properties in NEPA and the Barnett during 2022.

General and administrative

General and administrative expenses were $114.7 million, or $0.37 per Mcfe, for the year ended December 31, 2023, which was a decrease of $33.9 million, or 23%, from $148.6 million, or $0.53 per Mcfe, for the year ended December 31, 2022. The decrease in general and administrative expenses during the year ended December 31, 2023 compared to the year ended December 31, 2022 was due to a decrease in direct transaction costs from the Exxon Barnett Acquisition of $18.3 million, a decrease of $5.5 million in equity-based compensation, employee wages and contract labor and fees, and a decrease of $5.5 million in consulting and other general and administrative expenses. The decrease was also due to $8.0 million of BKVerde management fees incurred during 2023, compared to $13.0 million in 2022.

Other operating expenses

Other operating expenses were $12.6 million, or $0.04 per Mcfe, for the year ended December 31, 2023, which was an increase of $8.9 million from $3.6 million, or $0.01 per Mcfe, for the year ended December 31, 2022. The increase in other operating expenses during the year ended December 31, 2023 was primarily attributable to $3.6 million of inventory restocking and rig termination fees and $3.6 million of expenses incurred as a result of our decision to start selling third party gas. The remaining increase of $1.7 million was made up of individually immaterial increases.

Other Income (Expense)

Gains on contingent consideration liabilities. We recognized a gain on contingent consideration liabilities accruing as an earnout obligation under the purchase agreements executed in connection with the Devon Barnett Acquisition and the Exxon Barnett Acquisition. The gain on contingent consideration liabilities was $38.4 million for the year ended December 31, 2023, which was an increase of $31.8 million from the $6.6 million gain for the year ended December 31, 2022. The $38.4 million gain compared to the $6.6 million gain was primarily attributable to a gain on contingent consideration liabilities from the Devon Barnett Acquisition of $25.0 million. Higher decreases in forward curve commodity pricing for natural gas (NYMEX) and oil (WTI) assumptions used in the Monte Carlo simulations during the year ended December 31, 2023, compared to moderate decreases during the year ended December 31, 2022, further decreased the fair market value of the liability by $19.9 million. The remaining $11.8 million of the current period gain on contingent consideration liabilities was attributed to the 2022 Exxon Barnett Acquisition, which was also driven by decreases in forward curve commodity pricing compared to the year ended December 31, 2022.

Earnings from equity affiliate. Earnings from our equity affiliate was $16.9 million for the year ended December 31, 2023, which was a change of $8.4 million from $8.5 million compared to the same period in 2022. Earnings from our equity affiliate is related to our investment in, and our proportionate share in the income or losses of, the BKV-BPP Power Joint Venture. On July 10, 2023, the BKV-BPP Power Joint Venture acquired CXA Temple 2, LLC, the owner of 100% of the interests in Temple II, a combined cycle gas turbine and steam turbine power plant located on the same site as Temple I in the Electric Reliability Council of Texas North Zone in Temple, Texas, for an aggregate purchase price of $460.0 million. The Temple Plants deliver power to customers on the ERCOT power network in Texas.

Interest expense. Interest expense was $69.9 million for the year ended December 31, 2023, which was an increase of $43.6 million from $26.3 million for the year ended December 31, 2022. The increase in interest expense during the year ended December 31, 2023 was primarily driven by the term loans borrowed under our Term Loan Credit Agreement on June 30, 2022 and increased balances under our Revolving Credit Agreement and SCB Credit Facility.

Interest expense, related party. Interest expense from related parties was $7.1 million for the year ended December 31, 2023, which was a decrease of $3.7 million from $10.8 million for the year ended December 31, 2022. The decrease was primarily due to the payment in full of the loan under the $116 Million Loan Agreement (as defined herein) in 2022, which provided nine months of interest compared to none in 2023. This was slightly offset by an increase in the interest on the loan under the BNAC A&R Loan Agreement (as defined herein), which provided for seven months of interest in 2022 compared to a full year in 2023.

Other income. Other income was $8.4 million for the year ended December 31, 2023, which was an increase of $7.0 million from $1.4 million for the year ended December 31, 2022. The increase was due to the release of a service fee of $3.4 million originating from the Exxon Barnett Acquisition, a gain of $2.2 million recognized on the sale of other property and equipment, and the sale of surface rights of $1.1 million during the year ended December 31, 2023.

Income tax benefit (expense). Income tax expense was $28.2 million for the year ended December 31, 2023, which was a decrease of $34.5 million from $62.7 million for the year ended December 31, 2022. The year-over-year change was due primarily to the lower pre-tax income during the year ended December 31, 2023 compared to the year ended December 31, 2022.

Comparison of the Years Ended December 31, 2022 and 2021

Operating Revenues

Our operating revenues include revenues from the sale of natural gas, NGLs and oil, midstream revenues, gains and losses on our derivative contracts, marketing revenues and other revenues. The following table provides information on our revenues for the periods presented:

	Year Ended December 31,			
(in thousands, other than percentages)	2022	2021	$ Change	% Change
Revenues				
Natural gas revenues	$1,310,339	$ 597,050	$ 713,289	*
NGL revenues	311,542	225,135	86,407	38%
Oil revenues	11,866	7,560	4,306	57%
Midstream revenues	12,676	6,917	5,759	83%
Derivative losses, net	(629,701)	(383,847)	(245,854)	64%
Marketing revenues	11,001	52,616	(41,615)	(79)%
Related party and other	2,799	251	2,548	*
Total revenues and other operating income	$1,030,522	$ 505,682		

* *Percentage not meaningful*

Natural gas revenues

Our natural gas revenues increased by approximately $713.3 million to $1.3 billion for the year ended December 31, 2022 from $597.1 million for the year ended December 31, 2021. Higher production volumes, primarily from the 2022 Barnett Assets, during the year ended December 31, 2022 accounted for a $101.2 million increase in year-over-year revenues (calculated as the change in year-to-year volumes times the prior year average price).The impact of commodity price increases, excluding the effect of derivative settlements, provided a $612.1 million increase in year-over-year revenues (calculated as the change in the year-to-year average price times current year production volumes).

NGL revenues

Our NGL revenues increased by approximately $86.4 million to $311.5 million for the year ended December 31, 2022 from $225.1 million for the year ended December 31, 2021. Higher production volumes, primarily from the 2022 Barnett Assets, during the year ended December 31, 2022 accounted for a $8.2 million increase in year-over-year revenues (calculated as the change in year-to-year volumes times the prior year average price). The impact of commodity price increases, excluding the effect of derivative settlements, provided a $78.2 million increase in year-over-year revenues (calculated as the change in the year-to-year average price times current period production volumes).

Oil revenues

Our oil revenues increased by approximately $4.3 million to $11.9 million for the year ended December 31, 2022 from $7.6 million for the year ended December 31, 2021. Higher production volumes during the year ended December 31, 2022 accounted for a $1.1 million increase in year-over-year revenues (calculated as the change in year-to-year volumes times the prior year average price). This increase was also due to the impact of commodity price increases, excluding the effect of derivative settlements, which provided a $3.2 million increase in year-over-year revenues (calculated as the change in the year-to-year average price times current period production volumes).

Midstream revenues

Our midstream revenues increased by approximately $5.8 million to $12.7 million for the year ended December 31, 2022 from $6.9 million for the year ended December 31, 2021. This increase was primarily due to the midstream assets acquired in the Exxon Barnett Acquisition, slightly offset by decreases in the associated production of natural gas properties our legacy midstream assets support.

Derivative (losses) gains, net

For the year ended December 31, 2022, we had a loss on derivative contracts of $629.7 million compared to a loss on derivative contracts of $383.8 million for the year ended December 31, 2021. The increased loss for the year ended December 31, 2022 was attributable to increases in underlying commodity prices and volatility in energy markets, which resulted in higher realized losses on derivative contracts as well as $158.4 million of early terminations. This was offset by unrealized gains on derivative contracts of $58.8 million during the year ended December 31, 2022.

Marketing revenues

Our marketing revenues decreased by approximately $41.6 million to $11.0 million for the year ended December 31, 2022 from $52.6 million for the year ended December 31, 2021. Our marketing revenues are derived under our marketing agreement with a third party pursuant to which we receive a fixed percentage of all net income realized in the resale of our and other producers' hydrocarbons. The decrease in marketing revenues was primarily due to the pricing volatility surrounding the events of Winter Storm Uri, which resulted in $48.7 million of revenues for the year ended December 31, 2021. There were no events of this nature during the year ended December 31, 2022.

Related party and other

We generate a portion of our revenues from a management fee from the BKV-BPP Power Joint Venture. Our other revenues were approximately $2.8 million for the year ended December 31, 2022, as compared to $0.3 million for the year ended December 31, 2021.

Operating Expenses

Our operating expenses reflect costs incurred in the development, production and sale of natural gas, NGLs and oil. The following table provides information on our operating expenses:

	Year Ended December 31,			
(in thousands, other than percentages and average costs)	**2022**	**2021**	**$ Change**	**% Change**
Operating expenses				
Lease operating and workover	$131,497	$ 86,831	$44,666	51%
Taxes other than income	114,668	45,650	69,018	*
Gathering and transportation	208,758	173,587	35,171	20%
Depreciation, depletion, amortization and accretion	118,909	92,277	26,632	29%
General and administrative	148,559	85,740	62,819	73%
Other	3,567	1,274	2,293	*
Total operating expenses	$725,958	$485,359		
Average costs per Mcfe				
Lease operating and workover	$ 0.47	$ 0.35	$ 0.12	33%
Taxes other than income	0.41	0.19	0.22	*
Gathering and transportation	0.75	0.71	0.04	6%
Depreciation, depletion, amortization and accretion	0.43	0.37	0.06	16%
General and administrative	0.53	0.35	0.18	51%
Other	0.01	0.01	—	*
Total	$ 2.60	$ 1.98		

* *Percentage not meaningful*

Lease operating and workover

The following table summarizes our components of lease operating expenses for the periods presented:

	Year Ended December 31,					
	2022		2021			
(in thousands, other than percentages and average costs)	**Amount**	**Per Mcfe**	**Amount**	**Per Mcfe**	**$ Change**	**% Change**
Lease operating expenses	$123,386	$ 0.44	$83,028	$ 0.33	$40,358	49%
Workover expense	8,111	0.03	3,802	0.02	4,309	*
Total lease operating and workover expense	$131,497	$ 0.47	$86,831	$ 0.35	$44,666	51%

* *Percentage not meaningful*

Lease operating and workover expenses were $131.5 million, or $0.47 per Mcfe, for the year ended December 31, 2022, which was an increase of $44.7 million, or 51%, from $86.8 million, or $0.35 per Mcfe, for the year ended December 31, 2021. The increase in lease operating and workover expenses during the year ended December 31, 2022 compared to the same period in 2021 was primarily due to the Exxon Barnett Acquisition, which closed on June 30, 2022. The acquired operations drove $33.1 million of incremental lease operating and workover expenses during the year ended December 31, 2022. The remaining $13.9 million of increased lease operating and workover expenses was driven by a $4.5 million increase in labor costs, a $3.4 million increase in disposal costs, and $2.8 million increase in operating equipment costs. We had other increases of approximately $3.2 million of individually immaterial net increases in other direct production costs incurred in connection with our operations.

Taxes other than income

Taxes other than income were $114.7 million, or $0.41 per Mcfe, for the year ended December 31, 2022, which was an increase of $69.0 million from $45.7 million, or $0.19 per Mcfe, for the year ended December 31, 2021. The increase in taxes other than income during the year ended December 31, 2022 compared to 2021 was primarily due to increased natural gas and NGL production taxes associated with our operations from the 2020 Barnett Properties, which accounted for $33.7 million of the increase, as certain ad valorem and production taxes are not applicable to our NEPA natural gas properties. Property taxes related to our NEPA natural gas properties and our 2020 Barnett Assets increased by $13.0 million during 2022 compared to 2021. Ad valorem, production and property taxes related to the Exxon Barnett Acquisition accounted for the remainder of the increase in 2022 compared to 2021.

Gathering and transportation

Gathering and transportation expenses were $208.8 million, or $0.75 per Mcfe, for the year ended December 31, 2022, which was an increase of $35.2 million, or 20%, from $173.6 million, or $0.71 per Mcfe, for the year ended December 31, 2021. The increase was primarily due to certain gathering and transportation contracts from the Devon Barnett Acquisition, expiring in 2021, which required us to net the gathering and transportation fees with our natural gas, NGL and oil sales. Upon expiration, the contracts were replaced and expenses under the new contracts are presented as gathering and transportation expenses, accounting for approximately $19.0 million of gathering and transportation expenses during the year ended December 31, 2022. In addition, the Exxon Barnett Acquisition accounted for $10.3 million of the increase. The remainder of the increase in gathering and transportation expenses during the year ended December 31, 2022 compared to the same period in 2021 was due to an increase in volumes of $2.4 million and an increase in contractual rates with a third party of $1.5 million.

Depreciation, depletion, amortization and accretion

Depreciation, depletion, amortization and accretion was $118.9 million, or $0.43 per Mcfe, for the year ended December 31, 2022, which was an increase of $26.6 million, or 29%, from $92.3 million, or $0.37 per Mcfe, for the year ended December 31, 2021. The increase in depreciation, depletion, amortization and accretion during the year ended December 31, 2022, compared to the year ended December 31, 2021, was primarily due to the Exxon Barnett Acquisition, which accounted for an additional $22.9 million of depreciation, depletion, amortization and accretion expense during the year ended December 31, 2022. The remaining $3.7 million consisted of individually immaterial increases.

General and administrative

General and administrative expenses were $148.6 million, or $0.53 per Mcfe, for the year ended December 31, 2022, which was an increase of $62.8 million, or 73%, from $85.7 million, or $0.35 per Mcfe, for the year ended December 31, 2021. The increase in general and administrative expenses during the year ended December 31, 2022 compared to the year ended December 31, 2021 was primarily due to the Exxon Barnett Acquisition, which provided $14.5 million of additional general and administrative costs and $18.5 million in incremental costs which included direct transaction costs. Also during the year ended December 31, 2022, we had an increase in costs of $20.7 million related to equity-based compensation, employee wages and contract labor and fees compared to the same period in 2021. During 2022, we entered into an agreement with Verde CO2 and incurred $13.0 million for the management of BKVerde, as compared to an immaterial amount during 2021.

Other operating expenses

Other operating expenses were $3.6 million or $0.01 per Mcfe for the year ended December 31, 2022, which was an increase of $2.3 million from $1.3 million or $0.01 per Mcfe for the year ended December 31, 2021. The increase in other operating expenses was due to the increases in other operating expenses related to the 2022 Barnett Assets.

Other Income (Expense)

Bargain purchase gain. Bargain purchase gain increased to $170.9 million for the year ended December 31, 2022 from zero for the year ended December 31, 2021. The Exxon Barnett Acquisition resulted in a bargain purchase gain, which was primarily caused by the increase in commodity pricing from the date the acquisition was originally negotiated through the closing date. Because the value of the purchase consideration transferred was less than the fair value of the assets acquired and liabilities assumed as of the closing date of the Exxon Barnett Acquisition, we recognized a bargain purchase gain for the difference.

Gains (losses) on contingent consideration liabilities. We recognized a gain on contingent consideration liabilities accruing as an earnout obligation under the purchase agreements executed in connection with the Devon Barnett Acquisition and the Exxon Barnett Acquisition. The gain on contingent consideration liabilities was $6.6 million for the year ended December 31, 2022, which was an increase of $201.6 million from the $195.0 million loss for the year ended December 31, 2021. The $6.6 million gain in 2022 compared to the $195.0 million loss in 2021 was primarily attributable to the gain on contingent consideration liabilities with the Devon Barnett Acquisition of $5.1 million. Decreases in forward curve commodity pricing for natural gas (NYMEX) and oil (WTI) assumptions used in the Monte Carlo simulations during the year ended December 31, 2022, decreased the fair market value of the liability. The year ended December 31, 2021 showed increases in forward curve commodity pricing for natural gas and oil causing the fair value of the contingent consideration to increase the associated liability. The remaining $1.6 million of the current period gain on contingent consideration liabilities was attributed to the 2022 Exxon Barnett Acquisition, which was also driven by decreases in forward curve commodity pricing from the acquisition date.

Gain on settlement of litigation. Gain on settlement of litigation increased to $16.9 million for the year ended December 31, 2022 from zero compared to the same period in 2021 due to the settlement of a dispute between us and an operator related to a midstream gathering system. We agreed to settle with the operator in February 2022, receiving $35.0 million in the settlement. Of the $35.0 million received, $18.1 million was deemed the collection of accounts receivable. The remaining $16.9 million has been recognized as a gain on settlement of litigation on our consolidated statements of operations.

Interest expense. Interest expense was $26.3 million for the year ended December 31, 2022, which was an increase from zero compared to the same period in 2021. The increase in interest expense during the year ended December 31, 2022 was driven from our Term Loan Credit Agreement and Revolving Credit Facilities (defined herein), which did not carry balances during the year ended December 31, 2021.

Interest expense, related party. Interest expense from our related party was $10.8 million for the year ended December 31, 2022, which was an increase of $8.7 million from $2.1 million for the year ended December 31, 2021. The increase was due to increased borrowings with BNAC of $75.0 million under the $75 Million Loan Agreement and nine months of outstanding debt on the $116.0 million loan under the $116 Million Loan Agreement during 2022, compared to three months in 2021.

Income tax benefit (expense). Income tax expense was $62.7 million for the year ended December 31, 2022, which was a change of $103.2 million from an income tax benefit of $40.5 million compared to the same period in 2021. The year-over-year change was due primarily to the higher pre-tax income during the year ended December 31, 2022, compared to a pre-tax loss during the year ended December 31, 2021.

Earnings from equity affiliate. Earnings from our equity affiliate was $8.5 million for the year ended December 31, 2022, which was a change of $7.6 million from $0.9 million compared to the same period in 2021. Earnings from our equity affiliate is related to our investment and proportionate share in the income or losses of the BKV-BPP Power Joint Venture, which we entered into in November 2021.

Liquidity and Capital Resources

Liquidity

Since January 1, 2023, natural gas prices have decreased significantly from previous periods, which caused non-compliance with our fixed charge coverage ratio financial covenant as of the quarter ended June 30, 2023. Although our lenders waived such non-compliance, as discussed below, non-compliance with financial debt covenants will limit our ability to draw on our existing credit facilities and could also result in our debt agreements being called early, which would move certain noncurrent financial obligations to current. As a result, we would have insufficient liquidity and capital resources to be able to repay those obligations. Additionally, our reduced cash flow from operations could cause us not to meet our current and noncurrent financial obligations based on current forecasts. To alleviate these conditions our ultimate parent, Banpu, has agreed to provide funding to allow us to meet our financial obligations until June 30, 2025, if necessary.

On June 16, 2023, the lenders under the Term Loan Credit Agreement and the Revolving Credit Agreement agreed to: (i) waive compliance with our minimum consolidated fixed charge coverage ratio covenant for the quarter ending June 30, 2023; (ii) reduce the ratio required by our minimum consolidated fixed charge coverage ratio covenant to 1.00 to 1.00 for the quarters ending September 30 and December 31, 2023; (iii) waive compliance with our maximum total net leverage ratio covenant for the quarter ending December 31, 2023; and (iv) waive compliance with our required commodity hedging covenant for the quarters ending June 30, September 30 and December 31, 2023. Such waivers did not apply to our obligations in the Term Loan Credit Agreement and the Revolving Credit Agreement to satisfy such financial covenants in order to pay dividends on our common stock and to repay the loan under our BNAC A&R Loan Agreement. Additionally, on April 30, 2024, the lenders under the Revolving Credit Agreement agreed to waive compliance with respect to our minimum marketer receivables covenant for up to $60.0 million of our credit facility borrowings under the Revolving Credit Agreement with total borrowings not to exceed $100.0 million; this waiver was effective through the fiscal quarter ending December 31, 2023 and, on December 26, 2023, the lenders agreed to extend the effectiveness of this waiver until July 31, 2024. For additional information, see "*Risk Factors — Risks Related to Our Business Generally — If we are unable to comply with the restrictions and covenants in our debt agreements, there could be an event of default under the terms of such agreements, which could result in an acceleration of repayment.*"

Additionally, on September 29, 2023, we entered into the Fourth Amendment to the Term Loan Credit Agreement and the Fourth Amendment to the Revolving Credit Agreement with the respective lenders thereunder, pursuant to which such credit agreements were amended to (i) remove the Company's maximum total net leverage ratio covenant and minimum consolidated fixed charge coverage ratio covenant; and (ii) insert the following financial covenants: (a) minimum debt service coverage ratio, which could not be less than 1.05 to 1.00 at the end of each fiscal quarter and (b) maximum net indebtedness to equity ratio, which could not be greater than 1.50 to 1.00 at the end of each fiscal quarter.

The Fourth Amendment to the Term Loan Credit Agreement inserted an additional financial covenant which required us to hold a certain amount of cash in our Debt Service Reserve Account. To fund the Debt Service Reserve Account, BKV made a capital call on BNAC of $150.0 million and, pursuant to the requirements of the existing stockholders' agreement, on September 27, 2023, BNAC made such capital contribution in exchange for 7,500,000 shares of BKV common stock (taking into account the October 2023 one-for-two reverse stock split). $138.3 million of BNAC's capital contribution was placed in the Debt Service Reserve Account to comply with our financial covenant under the Term Loan Credit Agreement.

On June 11, 2024, the amounts outstanding under the Term Loan Credit Agreement, the Revolving Credit Agreement and the SCB Credit Facility were paid off with proceeds from the loans under the RBL Credit Agreement and cash on hand. The Term Loan Credit Agreement, the Revolving Credit Agreement and the SCB Credit Facility were terminated concurrently with the repayment of the remaining amounts owed thereunder.

On June 11, 2024, we entered into the RBL Credit Agreement.

Capital Commitments

Our primary needs for cash are to fund our upstream development, midstream, power, and CCUS projects, fund operations and capital expenditures, fund acquisitions, fund asset retirement obligations, cover any debt interest or minimum volume commitment obligations, paydown debt, and return capital to stockholders. Our primary uses of cash during the six months ended June 30, 2024 and 2023 were to fund the development of our natural gas properties. During the year ended December 31, 2023, our primary uses of cash were to fund the development of our natural gas properties and CCUS projects and during the year ended December 31, 2022, our primary use of cash was to fund our Exxon Barnett Acquisition. During the year ended December 31, 2021, our primary uses of cash were to fund our BKV-BPP Power Joint Venture, the development of our natural gas properties, and to pay a special dividend to our common stockholders. Also in 2021, the primary use of the cash received from BNAC was to fund the redemption of our outstanding preferred stock.

During the six months ended June 30, 2024 and 2023, capital expenditures for development of natural gas properties were $21.5 million and $113.1 million, respectively. During the years ended December 31, 2023, 2022, and 2021, capital expenditures for development of natural gas properties were $134.4 million, $235.4 million, and $63.9 million, respectively. Our current estimate for total capital expenditures in 2024 is approximately $52.0 million. Capital expenditures for our operated properties are largely discretionary and within our control. We could choose to defer a portion of these planned capital expenditures depending on a variety of factors, including, but not limited to, the success of our drilling activities, prevailing and anticipated prices for natural gas and NGLs, the availability of equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs, and the level of participation by other interest owners. We will continue to monitor commodity prices and overall market conditions and can adjust our rig cadence up or down in response to changes in commodity prices and overall market conditions.

Natural gas, NGL and oil prices have historically been volatile and decreased significantly in early 2023. Although natural gas prices started to increase in the second half of 2023, they are considerably lower than the near-record high prices experienced in 2022 and are projected to remain lower. Due to our desire to be a prudent operator and exercise capital discipline in this pricing environment, subsequent to finalizing our reserve reports as of December 31, 2023, we decreased our capital expenditures budget for development of natural gas properties for 2024 to approximately $13.0 million, which impacted our proved reserves, standardized measure value of proved reserves, and the PV-10 value of proved reserves as of December 31, 2023 by approximately 3.3%, 1.6%, and 2.0%, respectively. If the current lower natural gas commodity pricing environment extends beyond 2024, we will continue to maintain capital discipline and reflect corresponding capital expenditure changes in our estimated reserves as of December 31, 2023. These changes would mainly impact proved undeveloped reserves and proved developed non-producing reserves, which collectively represent approximately 25% of our total estimated proved reserves as of December 31, 2023.

Our operating leases consist of leases for office space and compressors. We do not have any finance leases. Leases with an initial term of 12 months or less are not recorded on the balance sheet. Instead, the short-term leases are recognized in expenses on a straight-line basis over the lease term. Most leases include one or more options to renew, with renewal terms generally being one year, which are not recognized as part of the ROU assets or lease liabilities on the condensed consolidated balance sheets as they are not reasonably certain to be exercised. The exercise of lease renewal options is at our discretion. As of June 30, 2024, our undiscounted minimum cash payment obligations for operating lease liabilities through 2033 were $9.4 million.

Capital Resources

Historically, our primary sources of capital resources and liquidity have consisted of internally generated cash flows from operations and loans with and capital contributions from our majority stockholder, BNAC. We also enter into derivative contracts to reduce the financial impact of commodity price volatility and provide a level of certainty and stability to our cash flows. We currently believe that we will be able to fully fund our 2024 capital budget, excluding our CCUS capital budget, with cash on hand and cash flows from operations. We expect to fund up to 50% of our CCUS business from a variety of external sources, which may include joint ventures, project-based equity partnerships and federal grants, with the remaining capital needs being funded with cash flows from operations. The following table summarizes our cash flows for the six months ended June 30, 2024 and 2023, as well as the years ended December 31, 2023, 2022, and 2021 (in thousands):

	Six Months Ended June 30,		Year Ended December 31,		
	2024	2023	2023	2022	2021
Net cash provided by operating activities	$ 9,782	$ 80,924	$ 123,076	$ 349,194	$ 358,133
Net cash provided by (used in) investing activities	101,633	(128,606)	(177,848)	(865,566)	(161,858)
Net cash provided by (used in) financing activities	(267,287)	(83,025)	66,713	534,833	(79,053)
Net increase (decrease) in cash, cash equivalents and restricted cash	$(155,872)	$(130,707)	$ 11,941	$ 18,461	$ 117,222

Cash flows provided by operating activities. Net cash provided by operating activities was $9.8 million for the six months ended June 30, 2024, compared to $80.9 million for the six months ended June 30, 2023. Net cash provided by operating activities decreased during the six months ended June 30, 2024 compared to the six months ended June 30, 2023 due to a reduction in net working capital of $87.8 million, a $39.3 million decrease in income from operations (excluding net unrealized gains (losses), depreciation, depletion, amortization, and accretion, equity-based compensation, and gain on sales of assets) resulting from lower natural gas prices compared to 2023, a $10.9 million increase in interest paid, and $3.9 million of transaction costs associated with the sale of BKV Chaffee and BKV Chelsea. These impacts were offset by reduced settlements of contingent liabilities of $45.0 million, cash received from the sale of call options for $23.5 million, and interest income earned on our restricted cash of $2.3 million during the six months ended June 30, 2024.

Net cash provided by operating activities was $123.1 million for the year ended December 31, 2023, compared to $349.2 million for the year ended December 31, 2022. Net cash provided by operating activities decreased during the year ended December 31, 2023 compared to the year ended December 31, 2022 primarily due to a $150.2 million decrease in income from operations (excluding net unrealized gains (losses), depreciation, depletion, amortization, and accretion, and equity-based compensation) resulting from lower natural gas prices compared to 2022, a $36.4 million decrease due to higher cash paid for interest, which was driven by the term loans borrowed under our Term Loan Credit Agreement on June 30, 2022 and increased balances under our Revolving Credit Agreement and Revolving Credit Facilities, a decrease in contingent consideration as prior year's $19.7 million was recognized in net cash provided by (used in) financing activities, and cash received on the settlement litigation in 2022 of $16.9 million.

Net cash provided by operating activities was $349.2 million for the year ended December 31, 2022, compared to $358.1 million for the year ended December 31, 2021. Net cash provided by operating activities decreased in 2022 primarily due to our net income position in 2022 versus our net loss in 2021, offset by cash paid for contingent consideration, current year gain on bargain purchase, changes in the fair value of derivatives and an increase in cash utilized for working capital.

Operating cash flow fluctuations are substantially driven by realized commodity prices, production volumes and operating expenses. Prices for natural gas and NGLs have historically been volatile, primarily as a result of supply and demand, pipeline infrastructure constraints, basis differentials, inventory storage levels and seasonal influences. We are unable to predict future commodity prices and therefore cannot provide assurance about future levels of cash provided by operating activities.

Cash flows provided by (used in) investing activities Net cash provided by investing activities was $101.6 million for the six months ended June 30, 2024, compared to net cash used in investing activities of $128.6 million for the six months ended June 30, 2023. Contributing to the cash inflow during the six months ended June 30, 2024 were the proceeds from the sale of BKV Chaffee and BKV Chelsea of $106.7 million and $25.0 million, respectively. The change was also due to the decrease of $91.6 million of expenditures in development and acquisition of natural gas properties for the six months ended June 30, 2024 compared to the six months ended June 30, 2023, and a loan advanced to BKV-BPP Power Joint Venture of $8.0 million during the six months ended June 30, 2023.

Net cash used in investing activities decreased from $865.6 million for the year ended December 31, 2022 to $177.8 million for the year ended December 31, 2023. The primary driver of the decrease was the $619.4 million used in connection with the Exxon Barnett Acquisition, which closed on June 30, 2022. Expenditures in development of natural gas properties also decreased by $101.0 million, which was offset by an increase of $50.0 million used in connection with the development of CCUS projects during the year ended December 31, 2023 compared to the year ended December 31, 2022.

Net cash used in investing activities increased from $161.9 million for the year ended December 31, 2021 to $865.6 million for the year ended December 31, 2022. Driving this increase was $619.4 million from our acquisition of certain operated and non-operated interests in proved reserves and certain midstream support assets in the Exxon Barnett Acquisition. Approximately $235.4 million of our cash outflows for the year ended December 31, 2022 was from our expenditures in development of natural gas properties. The remainder of the cash outflow was attributable to other investing activities.

Contributing to the $161.9 million cash outflow in 2021 was our initial investment in BKV-BPP Power. In November 2021, BKV-BPP Power purchased an operational power plant in Texas for $88.4 million. The remaining activity in 2021 included $63.9 million attributable to development activities and $7.6 million for developed property and undeveloped acreage acquisition. Development activities have and are anticipated to continue to be funded through cash flows from operations.

The following table presents our upstream capital expenditures (excluding leasehold costs and acquisitions) on an accrual basis for the six months ended June 30, 2024 and 2023, as well as the years ended December 31, 2023, 2022, and 2021 and reconciles to cash flows used in development of natural gas properties in the condensed consolidated statements of cash flows.

	Six Months Ended June 30,		Year Ended December 31,		
	2024	2023	2023	2022	2021
	(in thousands)				
Total use of cash and cash equivalents for development of natural gas properties	$ (21,509)	$ (113,090)	$(134,428)	$(235,406)	$(63,932)
(Increase) decrease in accrued development of natural gas properties	(4,019)	21,568	26,884	(17,773)	(13,702)
Upstream capital expenditures (accrued)	$ (25,528)	$ (91,522)	$(107,544)	$(253,179)	$(77,634)

Cash flows provided by (used in) financing activities. Net cash used in financing activities increased from $83.0 million for the six months ended June 30, 2023 to $267.3 million for the six months ended June

30, 2024. For the six months ended June 30, 2024, cash outflows were due to the payment on the outstanding balances on the Term Loan Credit Agreement and the Revolving Credit Agreement of $456.0 million and $85.0 million, respectively, and net payments on our SCB Credit Facility and payment on the BNAC A&R Loan Agreement of and $42.0 million and $25.0 million, respectively. In addition, we paid debt extinguishment costs of $10.2 million for the early retirement of the Term Loan Credit Agreement and the Revolving Credit Agreement, and $8.1 million of debt issuance costs on the RBL Credit Agreement. This was offset with net proceeds from the RBL Credit Agreement of $360.0 million. For the six months ended June 30, 2023, we paid down $114.0 million on the Term Loan Credit Agreement, which was offset by net proceeds from draws on the Revolving Credit Facilities of $36.0 million.

Net cash provided by financing activities decreased from $534.8 million for the year ended December 31, 2022 to $66.7 million for the year ended December 31, 2023. The drivers of the current period inflow were the $258.5 million and $117.0 million of advances received from the Revolving Credit Facilities and Revolving Credit Agreement, respectively. In addition, we received a capital contribution from BNAC in the amount of $150.0 million in exchange for 7,500,000 shares of our common stock. This was offset by cash outflows of $114.0 million, $272.5 million and $66.0 million for repayments made on our Term Loan Credit Agreement, Revolving Credit Facilities and Revolving Credit Agreement, respectively. The $534.8 million cash inflow for the year ended December 31, 2022 was due to proceeds of $570.0 million in connection with a term loan agreement and proceeds of $75.0 million in connection with a related party note payable, offset by repayments of $166.0 million to the related party, $190.0 million of advances received in connection with our OCBC Credit Facility, offset by repayments of $100.0 million on said facility and the financing portion of the settlement of contingent consideration of $19.7 million. The remainder of the fluctuation consisted of deferred offering cost payments, debt issuance costs and net share settlements.

Net cash provided by financing activities changed from a $79.1 million outflow for the year ended December 31, 2021 to a $534.8 million inflow for the year ended December 31, 2022. The primary driver of the current period inflow was the $570.0 million of borrowings against the Term Loan Credit Agreement dated June 16, 2022. We also received $75.0 million of proceeds in connection with a related party note payable, offset by $166.0 million of repayments to the related party, and $190.0 million of advances received from our credit facilities, offset by $100.0 million of repayments on these credit facilities. The remainder of the fluctuation consists primarily of contingent consideration settlements, debt issuance cost and deferred offering cost payments, and net share settlements.

Contributing to the net cash used in financing activities of $79.1 million for the year ended December 31, 2021 were exercises of our redemption option on all outstanding shares of preferred stock and the associated shares of common stock for $122.4 million, and dividend payments made to common stockholders and preferred stockholders of $88.1 million and $10.3 million, respectively. We also repaid $24.0 million of our intercompany loan agreements with BNAC, which was offset by $166.0 million of proceeds received under the new loan agreements with BNAC.

Working Capital

As of June 30, 2024, we had cash and cash equivalents of $9.2 million compared to $22.4 million of cash and cash equivalents as of June 30, 2023. Our net working capital was $3.9 million as of June 30, 2024 compared to a working capital deficit of $378.1 million as of June 30, 2023.

As of December 31, 2023, we had cash and cash equivalents of $25.4 and restricted cash of $139.7 million compared to $153.1 million of cash and cash equivalents as of December 31, 2022. Our net working capital deficit was $100.1 million as of December 31, 2023, compared to a deficit of $276.5 million as of December 31, 2022.

Our working capital fluctuates based on the timing of cash collections on accounts receivable and payments on accounts payable. Our collection of receivables has historically been timely, and losses associated with uncollectible receivables have historically not been significant.

Due to the fluctuation in natural gas prices and our business being capital intensive, we may incur working capital deficits in the future. We currently believe our cash flows from operations, cash on hand and borrowings under our RBL Credit Agreement will provide sufficient liquidity to fund our operations and our 2024 capital expenditure budget, excluding our CCUS business, and interest expense and debt repayments that are expected to settle during the next 12 months; however, sustained decreases in natural gas prices may limit our ability to do so.

We expect that our pace of development, production volumes, commodity prices and differentials to NYMEX prices for our oil and natural gas production will be the largest variables affecting our working capital.

Loan Agreements and Credit Facilities

Intercompany Loan Agreements

On December 17, 2019, BKV O&G entered into a Loan Agreement (the "$10 Million Loan Agreement") with BNAC, a related party, which allowed for a single drawdown in the amount of $10.0 million. On June 23, 2020, we entered into a novation agreement with BKV O&G and BNAC, which transferred all of BKV O&G's rights and obligations under the $10 Million Loan Agreement to us. Also on June 23, 2020, we entered into a First Amendment to the Loan Agreement (the "First Amendment to $10 Million Loan Agreement"). On July 1, 2020, we borrowed $10.0 million thereunder for working capital purposes. The First Amendment to $10 Million Loan Agreement bore interest at a rate calculated monthly based on the outstanding principal balance as of the first of the month at the rate no less than the cost of funding of BNAC. Interest was payable on a monthly basis. During the year ended December 31, 2020, we paid $0.2 million in interest on the loan, and on December 31, 2020, we repaid $5.0 million of the outstanding principal amount of the loan. During the year ended December 31, 2021, we paid $0.1 million in interest on the loan and repaid the remaining outstanding principal amount of the loan in full. The First Amendment to $10 Million Loan Agreement terminated on June 20, 2021.

On September 28, 2020, we borrowed $119.0 million under a Loan Agreement (the "$119 Million Loan Agreement") with BNAC to partially fund the Devon Barnett Acquisition and for working capital. The $119 Million Loan Agreement bore interest at six-month LIBOR plus 5.25% per annum and was payable on a semi-annual basis. During the year ended December 31, 2020, we paid $1.5 million in interest on the loan, and on December 16, 2020, we repaid $100.0 million of the original outstanding principal amount of the loan. During the year ended December 31, 2021, we paid $0.2 million in interest on the loan, and on March 15, 2021, we repaid the remaining outstanding principal amount of the loan in full. The $119 Million Loan Agreement terminated concurrently with repayment of the remaining principal amount.

On November 8, 2021, we borrowed $50.0 million under a Loan Agreement (the "$50 Million Loan Agreement") with BNAC. On January 11, 2022, we repaid $15.0 million of the outstanding principal amount of the loan. On June 1, 2022, we paid $1.3 million in interest on the loan and repaid the remaining $35.0 million of the outstanding principal amount of the loan in full. The $50 Million Loan Agreement terminated concurrently with the repayment of the remaining principal amount.

Subordinated Intercompany Loan Agreements

On October 14, 2021, we borrowed $116.0 million under a Loan Agreement (the "$116 Million Loan Agreement") with BNAC to redeem all of the outstanding preferred and common stock of the company owned by OCM BKV Holdings, LLC, an affiliate of Oaktree Capital Management L.P. Following such redemption, we do not have any issued and outstanding preferred stock. On June 15, 2022, we entered into an Amended and Restated Loan Agreement (the "$116 Million A&R Loan Agreement"), which amended and restated the $116 Million Loan Agreement to, among other things, subordinate the $116.0 million term loan owed to BNAC thereunder to the term loans we borrowed under the Term Loan Credit Agreement. On August 24, 2022, BNAC entered into a Subordination Agreement with Bangkok Bank Public Company Limited, New York Branch, which subordinated the $116.0 million term loan owed to BNAC to the revolving loans at any time outstanding under the Revolving Credit Agreement (the "August 2022 Subordination Agreement"). On September 16, 2022, we repaid the full $116.0 million balance of the loan.

On March 10, 2022, we borrowed $75.0 million under a Loan Agreement (the "$75 Million Loan Agreement") with BNAC to fund the deposit for the Exxon Barnett Acquisition. On June 15, 2022, we entered into an Amended and Restated Loan Agreement (the "BNAC A&R Loan Agreement" and, together with the $116 Million A&R Loan Agreement, the "Subordinated Intercompany Loan Agreements"), which amended and restated the $75 Million Loan Agreement to, among other things, subordinate the $75.0 million term loan owed to BNAC thereunder to the term loans under the Term Loan Credit Agreement. The BNAC A&R Loan Agreement provides for the subordination of the $75.0 million term loan owed to BNAC thereunder to the revolving loans at any time outstanding under the Revolving Credit Agreement. In connection with entering into the RBL Credit Agreement, our obligations under the BNAC A&R Loan Agreement were subordinated to our obligations under the RBL Credit Agreement.

Our payment obligation under the BNAC A&R Loan Agreement is unsecured and subordinated to our payment obligations under the Term Loan Credit Agreement and the Revolving Credit Agreement, both as discussed further below. The BNAC A&R Loan Agreement bears interest at SOFR plus 5.25%, is payable semi-annually, and is due on December 31, 2027, including any unpaid interest, unless such payment is prohibited by the subordination terms of the Term Loan Credit Agreement. Subject to such subordination provisions, we are permitted to prepay the BNAC A&R Loan Agreement at any time, with no prepayment premium.

The BNAC A&R Loan Agreement includes covenants that, among other things, prohibit us or any of our subsidiaries from merging, incurring liens or incurring any additional indebtedness or guarantees without consent from the lender. The BNAC A&R Loan Agreement includes financial covenants that require us to: (i) maintain a net worth (as defined in the BNAC A&R Loan Agreement, but generally meaning total assets minus total liabilities) of at least $800.0 million at all times; and (ii) not permit our trailing 12 month net borrowings to EBITDAX (as defined in the BNAC A&R Loan Agreement, but generally meaning the ratio of debt (minus cash) to earnings before interest, taxes, depreciation, depletion, amortization and exploration expenses) ratio to exceed 3.0 to 1.0 at any time. We are in compliance with all associated covenants under the BNAC A&R Loan Agreement as of June 30, 2024.

On June 18, 2024, we paid down $25.0 million of the $75.0 million on the BNAC A&R Loan Agreement, including interest.

Term Loan Credit Agreement

On June 16, 2022, we entered into a Credit Agreement (as amended, the "Term Loan Credit Agreement") with a syndicate of banks and Bangkok Bank Public Company Limited (New York Branch), as the administrative agent. The Term Loan Credit Agreement included $600.0 million of commitments for term loans used solely to fund a portion of the purchase price for the Exxon Barnett Acquisition. On June 30, 2022, we borrowed $570.0 million of term loans under the Term Loan Credit Agreement to partially fund the Exxon Barnett Acquisition. As discussed below, such term loans required annual principal payments of $114.0 million. We made the first annual principal payment of $114.0 million on June 23, 2023. Following such payment, $456.0 million of aggregate principal amount remained outstanding under the Term Loan Credit Agreement.

On June 11, 2024, we paid off the amounts outstanding under the Term Loan Credit Agreement with proceeds from the loans under the RBL Credit Agreement and cash on hand. We terminated the Term Loan Credit Agreement concurrently with the repayment of such outstanding borrowings.

Revolving Credit Facilities

On December 22, 2021, we entered into a $55.0 million uncommitted credit facility with Oversea-Chinese Banking Corporation Limited, which included a $25.0 million sublimit for the issuance of standby letters of credit (the "OCBC Credit Facility"). On December 29, 2023, we paid $0.2 million in accrued interest and repaid in full the $50.0 million of outstanding borrowings under the OCBC Credit Facility. We terminated the OCBC Credit Facility concurrently with the repayment of such outstanding borrowings.

We were also party to a $50.0 million uncommitted credit facility with Standard Chartered Bank, which included a $35.0 million sublimit for revolving loans (the "SCB Credit Facility" and, together with the OCBC Credit Facility, the "Revolving Credit Facilities"). On February 1, 2023, we entered into an amendment letter with Standard Chartered Bank that increased the limit of the SCB Credit Facility from $25.0 million to $50.0 million.

On June 11, 2024, we paid off the amounts outstanding under the SCB Credit Facility with proceeds from the loans under the RBL Credit Agreement and cash on hand. We terminated the SCB Credit Facility concurrently with the repayment of such outstanding borrowings.

Revolving Credit Agreement

On August 24, 2022, we entered into the Revolving Credit Agreement with Bangkok Bank Public Company Limited (New York Branch), as the administrative agent and sole initial lender. The Revolving Credit Agreement included $100.0 million of commitments for unsecured revolving loans used for short-term working capital and operating needs.

On June 11, 2024, we paid off the amounts outstanding under the Revolving Credit Agreement with proceeds from the loans under the RBL Credit Agreement and cash on hand. We terminated the Revolving Credit Agreement concurrently with the repayment of such outstanding borrowings.

RBL Credit Agreement

On June 11, 2024, BKV Corporation, as guarantor, and the RBL Borrower, as borrower, entered into the RBL Credit Agreement with Citibank, N.A., as the administrative agent, and the financial institutions party thereto. The RBL Credit Agreement includes a maximum credit commitment of $1.5 billion. As of June 11, 2024, the RBL Credit Agreement has a borrowing base of $800.0 million and an elected commitment of $600.0 million. As of August 12, 2024, $360.0 million of revolving borrowings and $16.6 million of letters of credit were outstanding under the RBL Credit Agreement, leaving $223.4 million of available capacity thereunder for future borrowings and letters of credit. The loans may be borrowed, repaid and reborrowed during the term of the RBL Credit Agreement. The RBL Credit Agreement will mature on June 12, 2028. The obligations under the RBL Credit Agreement are secured and guaranteed on a secured basis by BKV Corporation, the RBL Borrower and all of the RBL Borrower's current and future material restricted subsidiaries. Loans under the RBL Credit Agreement bear interest at one, three or six-month term SOFR or ABR, as applicable, plus a credit spread adjustment of 0.10% for SOFR borrowings, plus an applicable margin per annum. Interest is payable on the last day of each interest period and at maturity. We are obligated to pay certain fees to the lenders and administrative agent under the RBL Credit Agreement, including commitment fees on the average daily amount of the undrawn portion of the commitments.

The RBL Credit Agreement contains various restrictive covenants that, among other things, limit the RBL Borrower's ability and the ability of its restricted subsidiaries to, subject to certain exceptions: (i) incur indebtedness; (ii) incur liens; (iii) acquire or merge with any other company; (iv) sell assets or equity interests of their subsidiaries; (v) make investments; (vi) pay dividends or make other restricted payments; (vii) change their lines of business; (viii) enter into certain hedge agreements; (ix) enter into transactions with affiliates; (x) own any subsidiary that is not organized in the United States; (xi) prepay any unsecured senior or subordinated indebtedness; (xii) engage in certain marketing activities; and (xiii) allow, on a net basis, gas imbalances, take-or-pay or other prepayments with respect to their proved oil and gas properties.

Beginning with the fiscal quarter ending September 30, 2024, the RBL Credit Agreement requires the RBL Borrower and its restricted subsidiaries to always hedge not less than 50% of projected production from their proved developed producing reserves for the subsequent 24 calendar month period immediately following such required delivery date.

The RBL Credit Agreement also includes financial covenants that require the RBL Borrower to maintain:

- on a quarterly basis, a minimum Current Ratio (as defined in the RBL Credit Agreement) of no less than 1.00 to 1.00; and
- on a quarterly basis, a Net Leverage Ratio (as defined in the RBL Credit Agreement) of no greater than 3.25 to 1.00.

The RBL Credit Agreement includes customary equity cure rights that will enable us to cure certain breaches of the minimum current ratio covenant or the maximum net leverage ratio covenant.

The RBL Credit Agreement generally includes customary events of default for a reserve-based credit facility, some of which allow for an opportunity to cure. If an event of default relating to bankruptcy or other insolvency events occurs, the revolving loans will immediately become due and payable; if any other event of default exists, the administrative agent or the requisite lenders will be permitted to accelerate the maturity of the revolving loans. The RBL Credit Agreement is secured by substantially all of the assets of BKV Corporation, the RBL Borrower and its restricted subsidiaries that are guarantors, and upon an event of default the agent under the RBL Credit Agreement could commence foreclosure proceedings.

BKV-BPP Power and BKV-BPP Cotton Cove Joint Ventures

Under the terms of the BKV-BPP Cotton Cove LLC Agreement and the BKV-BPP Power LLC Agreement, we do not have the ability to unilaterally cause BKV-BPP Power or BKV-BPP Cotton Cove to make distributions. During the year ended December 31, 2023, BKV-BPP Power made a distribution of $10.0 million to BKV Corporation. During the six months ended June 30, 2024 and 2023 and during the years ended December 31, 2022 and 2021, no distributions were made by BKV-BPP Power or BKV-BPP Cotton Cove. In addition, we may be required to make additional capital contributions to one or both joint ventures to fund items approved in their respective annual budgets or other matters approved by their respective boards. Such additional capital contributions, which are not subject to any limit on the potential amount required, would reduce the amount of cash otherwise available to us. However, any additional capital contributions to the BKV-BPP Power Joint Venture must be approved by a majority of BKV-BPP Power's eight member board of managers, four of which are appointed by us and four of which are appointed by BPPUS. Similarly, any additional capital contributions to the BKV-BPP Cotton Cove Joint Venture must receive the unanimous approval of BKV-BPP Cotton Cove's six member board of managers, four of which are appointed by us and two of which are appointed by BPPUS. For more information about our joint ventures with BPPUS, see "*Certain Relationships and Related Party Transactions — BKV-BPP Power Joint Venture — BKV-BPP Power Limited Liability Company Agreement" and "Certain Relationships and Related Party Transactions — BKV-BPP Cotton Cove Joint Venture — BKV-BPP Cotton Cove Limited Liability Company Agreement*." Also see "*Risk Factors — Risks Related to Our Power Generation Business — We operate our power generation business through a joint venture which we do not control*" and "*Risk Factors — Risks Related to Our CCUS Business — We operate the Cotton Cove Project through a joint venture that requires the consent of BPPUS for certain material actions.*"

Internal Controls and Procedures

As an emerging growth company, we are not currently required to comply with the SEC's rules implementing Section 404 of the Sarbanes-Oxley Act, and therefore are not required to make a formal assessment of the effectiveness of our internal control over financial reporting for that purpose. Upon becoming a public company, we will be required to comply with the SEC's rules implementing Section 302 of the Sarbanes-Oxley Act, which will require our management to certify financial and other information in our quarterly and annual reports and provide an annual management report on the effectiveness of our internal control over financial reporting. Though we will be required to disclose material changes made to our internal controls and procedures on a quarterly basis, we will not be required to make our first annual assessment of our internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act until the year following our first annual report required to be filed with the SEC. We will not be required to have our independent registered public accounting firm attest to the effectiveness of our internal controls over financial reporting until our first annual report subsequent to our ceasing to be an "emerging growth company" within the meaning of Section 2(a)(19) of the Securities Act.

Material Weaknesses in Internal Control Over Financial Reporting

As of June 30, 2024, material weaknesses continued to exist in our internal control over financial reporting. A "material weakness" is a deficiency, or combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis. See "*Risk Factors — Risks Related to the Offering and Our Common Stock — We have identified material weaknesses in our internal control over financial reporting and may identify additional material weaknesses in the future, or otherwise fail* *to maintain effective internal control over financial reporting, which could result in a restatement of our financial statements or cause us to fail to meet our reporting obligations.*"

We did not design and maintain effective controls to communicate relevant information among departments to completely and accurately record and disclose transactions in the financial statements. This material weakness contributed to the following additional material weaknesses: we did not design and maintain effective controls related to (i) the accounting for stock awards and common stock with certain put rights, including the value and classification of such arrangements; and (ii) the communication and evaluation of terms and conditions set forth in complex contracts, including certain of our commodity derivative contracts, relevant to our compliance with financial covenants and related disclosures. These material weaknesses resulted in audit adjustments to share capital and other mezzanine equity accounts and liquidity disclosures in the consolidated financial statements as of December 31, 2021 and for the year then ended.

In addition, we did not design and maintain effective controls related to the accounting for income taxes, which were not designed at a sufficient level of precision or rigor to prepare and review the tax rate reconciliation, return to provision, income tax provision, related income tax assets and liabilities, and disclosures in the consolidated financial statements. This material weakness resulted in audit adjustments to income tax benefit, income taxes payable to related party and deferred tax assets in the consolidated financial statements as of December 31, 2021 and for the year then ended, and an immaterial audit adjustment to the supplemental cash flows information for cash payments for income taxes and a reclassification between oil and gas production and other taxes payable and other accrued liabilities within *Note 11 — Accounts Payable and Accrued Liabilities* to our consolidated financial statements, included elsewhere in this prospectus, as of and for the year ended December 31, 2023.

Each of the material weaknesses described above could result in a misstatement of the aforementioned account balances or disclosures that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected.

Notwithstanding these material weaknesses, we believe our condensed consolidated financial statements fairly present, in all material respects, our condensed consolidated financial condition as of June 30, 2024 and our condensed consolidated results of operations and cash flows for the six months ended June 30, 2024 and 2023, in accordance with GAAP. We also believe that our consolidated financial statements fairly present, in all material respects, our consolidated financial condition as of December 31, 2023 and 2022, and our consolidated results of operations and cash flows for the years ended December 31, 2023, 2022, and 2021, in conformity with GAAP.

We have begun to take steps towards remediating these material weaknesses primarily by designing and implementing additional internal controls, including those related to (i) the communication of relevant information across departments, (ii) the valuation and classification of stock awards and common stock with certain put rights, (iii) the communication and evaluation of terms and conditions included in complex contracts relevant to our compliance with financial covenants and related disclosures and (iv) the preparation and review of the income tax rate reconciliation, return to provision, income tax provision, related income tax assets and liabilities, and income tax disclosures. Although we believe we are addressing the internal control deficiencies that led to these material weaknesses, the measures we have taken, and plan to take, may not be effective.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that could give rise to material off-balance sheet arrangements. As of June 30, 2024, our material off-balance sheet arrangements and transactions included volume commitments of $354.1 million and letters of credit of $9.0 million against the RBL Credit Agreement. For further information regarding these arrangements, see *Note 10 — Commitments and Contingencies* to our condensed consolidated financial statements, included elsewhere in this prospectus and under "*— Loan Agreements and Credit Facilities — RBL Credit Agreement*."

Critical Accounting Policies and Estimates

Management's discussion and analysis of our financial condition and results of operations are based upon our historical consolidated financial statements, which have been prepared in accordance with GAAP.

The preparation of our financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of certain assets, liabilities and related 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. The following critical accounting policies relate to the more significant estimates and assumptions used in preparing the historical consolidated financial statements.

Accounting for Natural Gas and NGL Reserves Quantities and Standardized Measure of Future Cash Flows

We use the successful efforts method of accounting for natural gas producing activities. Under this method, the costs to acquire mineral interests in natural gas properties, to drill and equip exploratory leases that find proved reserves, and to drill and equip development leases and related asset retirement costs are capitalized. Costs to drill exploratory wells are capitalized, or suspended, pending determination of whether the wells have proved reserves. If we determine the wells do not have proved reserves, the costs are charged to expense. For exploratory wells that find reserves that cannot be classified as proved when drilling is completed, costs continue to be capitalized as suspended exploratory drilling costs if sufficient reserves have been found to justify completion as a producing well and sufficient progress is being made in assessing the reserves and the economic and operational viability of the project. We reassess the operational viability of our exploratory wells on at least a quarterly basis, which may involve use of significant judgment. If we determine that future appraisal drilling or development activities are unlikely to occur, the associated suspended exploratory well costs are expensed. In some instances, this determination may take longer than one year.

The processes we use to estimate quantities of proved and unproved developed natural gas, NGL and oil reserves and their values, future production rates, and future development costs are highly complex and requires significant subjectivity and estimation in the evaluation of available geological, engineering and economic data. The accuracy of any reserves estimate is a function of the quality of data available and of engineering and geological interpretation. The data used in developing reserves estimates may change significantly over time as a result of numerous factors, including, but not limited to, evolving production history, additional development activity, and continual reassessment of the viability of production under varying economic conditions. Although we take every reasonable effort to ensure our reserves estimates are representative of our actual reserves — for example, by involving independent reserves engineers in the assessment of the estimates — the subjective decisions and variances in the data available could give rise to revisions that could materially impact the accompanying historical consolidated financial statements.

Impairment of Natural Gas Properties

The evaluation of impairment of proved and unproved natural gas properties is considered a critical accounting policy due to the significant judgment and estimation involved in ascertaining the probability of future events, such as future market values of natural gas, NGLs and oil, future production costs, and future production volumes, as well as fair valuation of the properties in question. Changes in the judgments and estimates used in our evaluation of impairment, including, but not limited to, the expected future cash flows from natural gas reserves on our properties, could result in the cost of our proved and unproved properties not being recoverable and give rise to the need to record an impairment loss. Similarly, in the instance we determine the property is not recoverable, changes in the estimates and assumptions underlying the model used to derive the fair value of the properties in question may impact the output of the model, which could give rise to significant changes in the amount of impairment loss to record.

Revenue Recognition

We generate the majority of our revenues through the production and sale of natural gas and NGLs. The majority of these sales contracts are short-term in duration and the associated revenue is recognized once control of the distinct goods identified in the contract transfers to the customer at the delivery point specified within the contract. Such sales amounts are based on an estimate of when the volumes delivered at estimated prices, as determined by the applicable sales agreement, which is variable based on commodity pricing. We estimate our sales volumes based on company-measured volume readings. Natural gas and NGL sales are adjusted in subsequent periods based on data received from our purchasers, which for natural gas, NGL and oil sales occur within two months of product delivery. Historically, differences between estimated revenue and actual revenue have not been material but have potential to be in the instance our price or volume estimates are inaccurate.

Non-operated and operated midstream revenues are recognized when services are rendered based on quantities transported and measured according to the underlying contracts. We record midstream revenues based on volumes at stated contractual rates. We estimate our non-operated midstream revenue volumes based on third party data with respect to our proportionate share of non-operated volumes and actual gross volumes for operated midstream revenues. Non-operated midstream revenues are adjusted in subsequent periods based on data received from the operator that reflects actual volumes, which is typically within three months.

Derivative Instruments

We enter into commodity derivative instruments to reduce the effect of price volatility on a portion of our future natural gas and NGL production. These activities may prevent us from realizing the full benefits of price increases above the levels of the derivative instruments on a portion of our future natural gas and NGL production. The commodity derivative instruments are measured and recorded at fair value and included in our condensed consolidated balance sheets. Such fair values are calculated based on the market approach, which uses industry standard models, assumptions and inputs. These assumptions and inputs are substantially observable in active markets throughout the full term of the instruments. These include market price curves, contract terms and prices, credit risk adjustments, implied market volatility and discount factors.

We have not designated any of our derivative contracts as fair value or cash flow hedges for accounting purposes and therefore we do not apply hedge accounting to the commodity derivative instruments. Therefore, net unsettled gains and losses on our commodity instruments are recorded based on the changes in the fair values of the derivative instruments and included within derivative gains (losses), net in the condensed consolidated statements of operations in the period of change.

Derivative instruments are with counterparties of high credit quality and are subject to master netting agreements, and accordingly, the risk of nonperformance by the counterparties is low. However, these activities may prevent us from realizing the full benefits of price increases above the levels of the derivative instruments on a portion of our future natural gas and NGL production.

Acquisitions

We account for business combinations in accordance with ASC Topic 805,*Business Combinations.* Pursuant to the guidance, we allocate the aggregate purchase consideration transferred to affect the business combination to the assets acquired and liabilities assumed based on their fair values as of the acquisition date. Any excess or shortage of the purchase price over the fair value of the assets acquired and liabilities assumed is recognized as goodwill or a gain on bargain purchase, respectively. The amount of goodwill or gain on bargain purchase recorded in a business combination can vary significantly depending on the fair value allocated to the assets acquired and liabilities assumed. Further, in many cases, the valuation of these assets and liabilities requires use of various estimates and assumptions and the exercise of significant judgment about future events.

In transactions where substantially all the gross assets acquired are concentrated in a single identifiable asset or group of similar identifiable assets, the acquisition is treated as an asset acquisition rather than a business combination. We account for asset acquisitions using a purchase price allocation through which the total transaction value is determined by aggregating the base purchase price, certain closing adjustments and contingent consideration, if any. The total transaction value is then allocated to the acquired assets on a pro rata basis based on their fair values. This allocation may cause identified assets to be recognized at amounts that are greater than their fair values. However, “non-qualifying” assets, which include financial assets and other current assets, should not be assigned an amount greater than their fair value. The determination of fair values of assets acquired requires us to make estimates and use valuation techniques. The transaction costs associated with asset acquisitions are capitalized as part of the assets acquired.

As part of the acquisitions made, we are also required to pay additional cash considerations, which are based on certain thresholds being met using forecasted monthly Henry Hub prices, WTI prices and the application of Monte Carlo simulations. This contingency, including the settlement, is described further in "*Note 10 — Commitments and Contingencies*" to our condensed consolidated financial statements included elsewhere in this prospectus. It is also described in "*Note 16 — Commitments and Contingencies*" to our audited consolidated financial statements included elsewhere in this prospectus. Future results of operations for any quarterly or annual period could be materially affected by changes in our assumptions.

Equity-Based Compensation

Pursuant to the BKV Corporation 2021 Long Term Incentive Plan (the "2021 Plan"), time-vested restricted stock units ("TRSUs") and performance-vested restricted stock units ("PRSUs") may be granted to eligible participants. In each of January 2021, 2022 and 2023, we made annual grants of TRSUs under the 2021 Plan. The 2021 Plan terminated on January 1, 2024 and no further awards will be made thereunder. Termination of the 2021 Plan pursuant to its terms will not affect the Company's or participants' rights as to all outstanding unvested or vested awards, and shares of common stock issued in settlement of awards. See "*Executive Compensation — BKV Corporation 2021 Long Term Incentive Plan — Amendment and Termination*" for more information about the termination of the 2021 Plan.

We recognize compensation cost related to equity-based awards under the 2021 Plan on a straight-line basis based on estimated grant date fair value, as if all four tranches of the TRSUs were granted at once, rather than being granted on an annual basis over four years. Under the 2021 Plan, if a participant's employment is terminated for any reason other than the participant's resignation or, if a participant's employment is terminated due to his or her voluntary resignation and more than 36 months has passed since the participant's first grant of an incentive award under the 2021 Plan, in each case where the Company had not repurchased the participant's shares of common stock acquired under the 2021 Plan, the participant will have the right to elect to sell such shares back to the Company at an amount equal to the fair market value of the shares at the time the election to sell was made. In November 2021, this put right was amended so that it could not be exercised for at least 181 days following the date the participant's award vests and a "Sell Fund Purchase Program" was implemented whereby, if specifically provided for in an award agreement, participants have the ability to tender shares for repurchase by the Company. The "Sell Fund Purchase Program" expired on December 31, 2023.

The TRSUs we are authorized to grant include service conditions and the PRSUs we are authorized to grant include service conditions, market performance conditions and non-market performance conditions. In January 2021, we anticipated that we would have made four annual grants of TRSUs under the 2021 Plan in each of 2021, 2022, 2023 and 2024, subject to continued employment, the continuation of the 2021 Plan and other factors; however, there was and is no obligation to make any future grants and any such grants would require approval by our board of directors. Although the TRSUs anticipated to be granted in each of 2022, 2023 and 2024 were not actually granted to the participants when their initial TRSU award was granted, for accounting purposes, the grant date fair value of the anticipated (but not yet granted) TRSUs was determined, based on the service condition and utilizing the fair market value of common stock on the date the 2021 TRSUs were granted. The grant date fair value of the PRSUs was determined based on the service conditions, market performance conditions and non-market performance conditions of the award on the grant and utilizing the fair market value of common stock on the grant date and Monte Carlo simulations, as well as probability assessments relative to the satisfaction of non-market performance conditions. In connection with the change to the put right to implement the 181-day holding period after vesting, an additional charge was recognized with respect to both the TRSUs and PRSUs, given that the fair market value of the common stock on the date of modification had increased from the fair market value on the original grant date.

Compensation cost is recognized ratably on a straight-line basis over the applicable service period. Forfeitures are estimated and recognized over the applicable service period and are re-evaluated at the end of each reporting period. We expect to recognize the forfeitures of the 2024 anticipated TRSUs in connection with this offering and the subsequent termination of the 2021 Plan.

We believe that our board of directors, with input from management and the support of third-party valuations, has the relevant experience and expertise to determine the fair value of our common stock.

Given the absence of a public trading market of our common stock, and in accordance with the American Institute of Certified Public Accountants Practice Aid, Valuation of Privately-Held Company Equity Securities Issued as Compensation, numerous objective and subjective factors were considered when determining the best estimate of the fair value of our common stock at each grant date. These factors include:

- the lack of marketability of our common stock;
- our operating and financial performance;
- current business conditions and projections;
- hiring of key personnel and the experience of our management;
- the history of the Company;
- the market performance of comparable publicly traded companies; and
- U.S. and global capital market conditions.

In valuing our common stock, the fair value of our business was determined using various valuation methods, including combinations of income and market approaches with input from management. The income approach estimates value based on the expectation of future cash flows that a company will generate. These future cash flows are discounted to their present values using a discount rate that is derived from an analysis of the cost of capital of comparable publicly traded companies in our industry or engaged in similar business operations as of each valuation date and is adjusted to reflect the risks inherent in our cash flows. The market approach estimates value based on a comparison of the subject company to comparable public companies engaged in similar business operations. From the comparable companies, a representative market value multiple is determined and then applied to the subject company's financial forecasts to estimate the value of the subject company.

Application of these approaches and methodologies involves the use of estimates, judgments, and assumptions that are highly complex and subjective, such as those regarding our expected future revenue, expenses, and future cash flows, discount rates, market multiples, the selection of comparable public companies, and the probability of and timing associated with possible future events. Changes in any or all of these estimates and assumptions or the relationships between those assumptions impact our valuations as of each valuation date and may have a material impact on the valuation of our common stock.

Once our stock is publicly traded, the fair value of each share of underlying common stock will be determined based on the closing price as reported on the date of grant on the primary stock exchange on which our common stock is traded.

Impairment of Goodwill

Goodwill represents the excess of the cost of an acquisition over the fair value of the net assets acquired through the corporate restructuring of BKV O&G and Kalnin Ventures to form BKV Corporation, as described in "*Business — Our History — The Corporatization Event*." Impairment may occur if the reporting unit's carrying value exceeds its fair value. Goodwill is tested at the reporting unit level, which is at the consolidated level due to BKV having one identifiable operating segment or reporting unit. We perform an impairment test for goodwill at least annually or when events and circumstances indicate the carrying value may not be recoverable. In performing the required impairment tests, we have the option to first assess qualitative factors to determine if it is necessary to perform a quantitative assessment for goodwill impairment. If the qualitative assessment concludes that it is more-likely-than-not that the fair value of a reporting unit is less than its carrying value, a quantitative assessment is performed.

Our quantitative assessment utilizes present value (discounted cash flow) methods to determine the fair value of the reporting units with goodwill. Determining fair value using discounted cash flows requires considerable judgment and is sensitive to changes in underlying assumptions and market factors. Key assumptions relate to revenue growth, projected operating income growth, terminal values, and discount rates. If current expectations of future growth rates and margins are not met, or if market factors outside of our control, such as factors impacting the applicable discount rate, or economic or political conditions in key markets change significantly, then goodwill allocated to the reporting unit may be impaired. Management determined there were no circumstances indicating the carrying value may not be recoverable during the years ended December 31, 2023, 2022 and 2021. There have been no impairments recorded related to goodwill as the results of the annual quantitative impairment test indicated the fair value of the assets of the reporting unit to be greater than the carrying value as of December 31, 2023 and 2022.

Litigation and Environmental Contingencies

In the ordinary course of business, we may at times be subject to claims and legal actions. Management does not believe the impact of such matters will have a material adverse effect on our financial position or results of operations.

We are subject to extensive federal, state, and local environmental laws and regulations, which may materially affect our operations. These laws, which are constantly changing, regulate the discharge of materials into the environment and may require us to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites.

In our acquisition of existing assets, we may not be aware of what environmental safeguards were taken during the time such assets were operated, and it is possible we may acquire certain environmental liabilities along with such assets.

We maintain comprehensive insurance coverage that we believe is adequate to mitigate the risk of any adverse financial effects associated with these risks. However, should it be determined that a liability exists with respect to any environmental cleanup or restoration, the liability to cure such a violation could still fall upon us. No claim has been made, nor are we aware of any liability which we may have, as it relates to any material environmental cleanup, restoration, or the violation of any rules or regulations relating thereto.

Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed as incurred. Liabilities for expenditures of a noncapital nature are recorded when environmental assessment and/or remediation is probable, and the cost can be reasonably estimated.

Recent Accounting Pronouncements

See "*Note 1 — Business and Basis of Presentation*" to our condensed consolidated financial statements and "*Note 2 — Summary of Significant Accounting Policies*" to our audited consolidated financial statements included elsewhere in this prospectus for more information about recent accounting pronouncements, the timing of their adoption, and our assessment, to the extent we have made one, of their potential impact on our financial condition and our results of operations.

Quantitative and Qualitative Disclosure About Market Risk

Commodity Price Risk and Hedging Activities

Our primary market risk exposure is in the price we receive for our natural gas and NGLs production. Pricing is primarily driven by spot regional market prices applicable to our U.S. natural gas production. Pricing for natural gas and NGLs has historically been volatile and unpredictable, and we expect this volatility to continue in the future. The prices we receive for our production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index price.

To mitigate some of the potential negative impact on our cash flows caused by changes in commodity prices, we enter into financial derivative instruments for a portion of our natural gas and NGLs production when management believes that favorable future prices can be secured.

Our financial hedging activities are intended to support natural gas and NGLs prices at targeted levels and to manage our exposure to natural gas and NGLs price fluctuations. These contracts may include commodity price swaps, whereby we will receive a fixed price and pay a variable market price to the contract counterparty, producer collars that set a floor and ceiling price for the hedged production, enhanced three-way collars that set a floor and ceiling price for the hedged production with the potential for hedged volumes doubling above the ceiling price, or basis differential swaps. These contracts are financial instruments and do not require or allow for physical delivery of the hedged commodity. The derivative contracts outstanding as of June 30, 2024 consisted of commodity price swaps, basis differential swaps, call options and producer collar agreements, subject to master netting agreements with each individual counterparty.

These derivative contracts cover portions of our projected positions through 2027. Our commodity hedge position as of June 30, 2024 is summarized in "*Note 5 — Derivative Instruments*" to our condensed consolidated financial statements included elsewhere in this prospectus.

We may enter into single hedge transactions with settlements up to 48 months. The aggregation of these executed hedge instruments may not exceed 60% of our forecasted production volumes for the current year and subsequent year, and for up to 40% and 25% of our forecasted production volumes in each of the respective subsequent years thereafter. During the six months ended June 30, 2024, a hypothetical increase or decrease of $0.10 per Mcf in NYMEX would have resulted in a $4.2 million decrease or increase in natural gas hedge revenues, respectively, and a hypothetical increase or decrease of $1.00 per Bbl of NGL purity product price would have resulted in a $3.0 million decrease or increase in NGL hedge revenues, respectively. During the year ended December 31, 2023, a hypothetical increase or decrease of $0.10 per Mcf in NYMEX would have resulted in a $1.6 million decrease or increase in natural gas hedge revenues, respectively, and a hypothetical increase or decrease of $1.00 per Bbl of NGL purity product price would have resulted in a $1.9 million decrease or increase in NGL hedge revenues, respectively.

Additionally, to reduce its exposure to fluctuations in the market price of electricity and natural gas, BKV-BPP Power enters into financially settled HRCOs, which are contracts for the financial purchase and sale of power based on a floating price of natural gas at a predetermined location using a predetermined conversion factor, or heat rate, required to turn the fuel input into electricity. BKV-BPP Power is exposed to basis risk in its operations when its derivative contracts settle financially and it delivers physical electricity on different terms. For example, if BKV-BPP Power enters into an HRCO, it hedges its electricity production based on an agreed price for that electricity, but physical electricity must be delivered to delivery points in the market it serves. BKV-BPP Power is exposed to basis risk between the hub price specified in the HRCO and the price that it receives for the sales of physical electricity. BKV-BPP Power attempts to hedge basis risk where possible, but hedging instruments are sometimes not economically feasible or available in the quantities that it requires. BKV-BPP Power's hedging activities do not provide it with protection for all of its basis risk and could result in economic losses and liabilities, which could have a material adverse effect on the BKV-BPP Power Joint Venture, and thus on our business, financial condition, results of operations and cash flows. Additionally, by using derivative instruments to economically hedge exposure to changes in power prices, we could limit the benefit we would receive from increases in the power prices, which could have an adverse effect on our financial condition. Moreover, in the event BKV-BPP Power is not able to satisfy its obligations under the HRCO, it must purchase power at prevailing market prices to satisfy the HRCO. Likewise, increases in power pricing could limit the benefit we receive under HRCOs and may result in losses. Either such event could have a material adverse effect on the BKV-BPP Power Joint Venture, and thus on our business, financial condition, results of operations and cash flows.

All derivative instruments, other than those that meet the normal purchase and normal sale scope exception, are recorded at fair market value in accordance with GAAP and are included in our condensed consolidated balance sheets as assets or liabilities. The fair values of our derivative instruments are adjusted for non-performance risk. Because we do not designate these derivatives as accounting hedges, they do not receive hedge accounting treatment; therefore, all mark-to-market gains or losses, as well as cash receipts or payments on settled derivative instruments, are recognized in our condensed consolidated statements of operations. We present total gains or losses on commodity derivatives (for both settled derivatives and derivative positions which remain open) within operating revenues as derivative gains (losses), net.

Mark-to-market adjustments of derivative instruments cause earnings volatility but have no cash flow impact relative to changes in market prices until the derivative contracts are settled or monetized prior to settlement. We expect continued volatility in the fair value of our derivative instruments. Our cash flows are only impacted when the associated derivative contracts are settled or monetized by making or receiving payments to or from the counterparty. As of June 30, 2024, the estimated fair value of our commodity derivative instruments was a net liability of $0.1 million, comprised of current assets and noncurrent liabilities. As of December 31, 2023, the estimated fair value of our commodity derivative instruments was a net asset of $102.5 million, comprised of current and noncurrent assets, and as of December 31, 2022, the estimated fair value of our commodity derivative instruments was a net liability of $46.0 million, comprised of current and noncurrent assets and current liabilities.

By removing price volatility from a portion of our expected production through December 2027, we have mitigated, but not eliminated, the potential negative effects of changing prices on our operating cash flows for those periods. While mitigating the negative effects of falling commodity prices, these derivative contracts also limit the benefits we would receive from increases in commodity prices above the fixed hedge prices.

Counterparty Credit Risk

We routinely monitor and manage our exposure to counterparty risk related to derivative contracts by requiring specific minimum credit standards for all counterparties, actively monitoring counterparties' public credit ratings, and avoiding concentration of credit exposure by transacting with multiple counterparties. Our commodity derivative contract counterparties are typically financial institutions with investment-grade credit ratings.

We enter into International Swap Dealers Association ("ISDA") Master Agreements with each of our derivative counterparties prior to executing derivative contracts. The terms of the ISDA Master Agreements provide, among other things, the Company and the counterparties with rights of set-off upon the occurrence of defined acts of default by either us or counterparty to a derivative contract.

In addition, we utilize an unaffiliated third party to market all of our natural gas production to various purchasers, which consist of credit-worthy counterparties, including utilities, LNG producers, industrial consumers, major corporations and super majors, in our industry. We rely on the credit worthiness of such third party marketer, who collects directly from the purchasers and remits to us the total of all amounts collected on our behalf less their fee for making such sales. See "*Business — Customers and Product Marketing"* and "*Risk Factors — Risks Related to Our Upstream Business and Industry — A substantial percentage of our natural gas and NGL production is gathered, processed and transported by a single third party and all of our natural gas production is marketed by a single third party.*"

Interest Rate Risks

As of June 30, 2024, our primary exposure to interest rate risk results from our outstanding related party borrowings with BNAC and our RBL Credit Agreement, both of which have a floating interest rate. As of June 30, 2024, we had $50.0 million of outstanding borrowings with BNAC and $360.0 million of outstanding borrowings under the RBL Credit Agreement. The average annualized interest rate incurred on our outstanding borrowings during the six months ended June 30, 2024 was approximately 9.4%. We estimate that a 1.0% increase in the applicable average interest rates during the six months ended June 30, 2024 would have resulted in an increase of $3.4 million in interest expense.

As of December 31, 2023, our primary exposure to interest rate risk resulted from our outstanding related party borrowings with BNAC, the Term Loan Credit Agreement, the Revolving Credit Agreement, and the SCB Credit Facility, which have floating interest rates. As of December 31, 2023, we had $75.0 million of outstanding borrowings with BNAC, $456.0 million of outstanding borrowings under the Term Loan Credit Agreement, $31.0 million of outstanding borrowings under the SCB Credit Facility, and $96.0 million of outstanding borrowings under the Revolving Credit Agreement. The average annualized interest rate incurred on our outstanding borrowings during the year ended December 31, 2023 was approximately 8.7%. We estimate that a 1.0% increase in the applicable average interest rates during the year ended December 31, 2023 would have resulted in an increase of $7.8 million in interest expense.

INDUSTRY

Our core business is to produce natural gas from our owned and operated upstream businesses, which are supported by our four business lines: natural gas production; natural gas gathering, processing and transportation (our "natural gas midstream business"); power generation; and carbon capture, utilization and sequestration ("CCUS"). We expect our owned and operated upstream and natural gas midstream businesses to achieve net zero Scope 1 and Scope 2 emissions by the early 2030s, and net zero Scope 1, 2 and 3 emissions by the late 2030s. We formally launched our CCUS business, BKV dCarbon Ventures, in March 2022, and then, in June 2022, we reached FID and entered into a definitive agreement with EnLink in connection with our first high concentration CCUS project in the Barnett, which we refer to as the Barnett Zero Project. Subsequently, in October 2022, we reached internal FID on our second CCUS project, which we refer to as the Cotton Cove Project. We achieved first injection of CO_2 waste at the Barnett Zero Project in November 2023. In addition, we expect to continue to identify and evaluate additional CCUS projects. CCUS projects and the sector generally are in their early stages and continue to evolve since the 2015 Paris Climate Agreement (the "Paris Agreement") drew global commitment to delivering a net-zero emission economy.

We formally launched our CCUS business, BKV dCarbon Ventures, in March 2022 and currently have commenced commercial operations at the Barnett Zero Project. However, our CCUS business and nearly all of our CCUS projects are in the early stages of development and we have not reached FID with respect to or entered into the definitive agreements necessary to execute nearly all of the other potential projects described in "*Business — Our Operations — Carbon Capture, Utilization and Sequestration*." CCUS projects and the sector generally are in their early stages and continue to evolve since the 2015 Paris Climate Agreement (the "Paris Agreement") drew global commitment to delivering a net-zero emission economy. For more information about the risks involved in our CCUS business, see "*Risk Factors — Risks Related to Our CCUS Business*."

Carbon Capture, Utilization and Sequestration

CCUS involves the capture of CO_2 emissions and the processing of such emissions for reuse or permanent storage in subsurface geological formations, and is recognized as a primary means of reducing CO_2 emissions from large-scale energy and industry sources.

To advance the objectives outlined in the Paris Agreement, the United States released goals in 2021 that included delivering a net-zero emission economy by no later than 2050 (and 2035 for the electric power sector). According to Global CCS Institute's Global Status of CCS 2021, the global CCUS industry must grow by more than a factor of 100 by the year 2050 to achieve Paris Agreement climate targets, equating to approximately 70 to 100 new facilities per year and achieving long-term emissions reduction targets will require installed CCUS capacity to increase to over 5,600 Mtpa by 2050 and an estimated capital investment of $655 billion to $1.280 trillion by 2050.

According to the Global Status of CCS 2022 Report, as of September 2022, there were 196 projects in the worldwide CCUS facilities pipeline (including two suspended projects). This represents an impressive 44% year over year growth and continues the upward momentum in CCUS projects in development. Additionally, the Global CCS Institute reported that, as of September 2022, 30 CCUS facilities were operational around the world. In Energy Technology Perspectives 2020, published by the International Energy Agency ("IEA"), the IEA estimated that 80% of industrial facilities and power plants accounting for 85% of emissions are located within 100 kilometers of a potential storage site.

To stimulate investment in CCUS, the US Energy Act of 2020 provided over $6 billion for CCUS research and development programs, and in 2021, the U.S. Treasury and the Internal Revenue Service ("IRS") issued critical guidance on Section 45Q tax credits for carbon capture and storage, expanding its applications to a wider range of CCUS activities. In addition, the Inflation Reduction Act of 2022 provides significant incentives for CCUS investment.

The current CCUS industry can be described as highly fragmented with a wide range of technologies and processes being evaluated for long-term viability across the value chain including capture, separation, compression, liquefaction, transportation, storage and utilization. According to the Global Status of CCS 2022 Report, CCUS has become increasingly commercial and competitive in many countries and CCUS networks involving the use of shared transport and storage infrastructure are becoming the predominant method of CCUS deployment, which benefits smaller projects that lack vertical integration.

Power Generation

The United States electricity market starts with utility-scale generators that generate electricity from fossil fuels, nuclear energy and renewable energy. Utility scale plants and other renewable energy sources sell electricity to the wholesale market, including electric utility companies, competitive power providers and electricity marketers, who then sell electricity to retail end-users.

The power industry consists of a variety of companies that are engaged in the generation or distribution of power, with most electric utility companies relying on natural gas to generate a portion of their power. According to the IEA, overall demand for electricity decreased during the initial phases of COVID-19, but has since increased as lockdowns subsided and manufacturing activities re-bounded. According to the IEA, global electricity demand rose by 6% in 2021, 2% in 2022 and is expected to rise by an average of 3% over the next three years.

In the near future, demand for retail electricity is expected to grow modestly, driven by increased consumption from commercial and industrial customers recovering from the pandemic. The United States recorded a significant 2.6% year over year demand increase in 2022, driven by economic activity and higher residential use to meet both heating and cooling needs. Short-term demand for electricity can vary with weather conditions and economic shocks, which increases unpredictability. Because long-term demand depends on economic growth and efficiency improvements, the growth of the national economy directly impacts U.S. power consumption.

The sources for U.S. electricity have increasingly consisted of natural gas and renewable energy sources. While coal and nuclear energy sources have been declining, natural gas and renewable sources have been expanding their share of total electricity generation in the United States. According to the IEA, in 2022, renewables grew to account for the largest share of total utility-scale electricity generating capacity in the United States at 36%, followed by natural gas at 33%. According to the IEA, the share of natural gas-based electricity generation tripled from 12% in 1990 to 36% in 2022. Given the multi-year highs in natural gas procurement pricing and supply chain constraints, capital spending budgets and customer affordability concerns are expected to increase.

Liquified Natural Gas

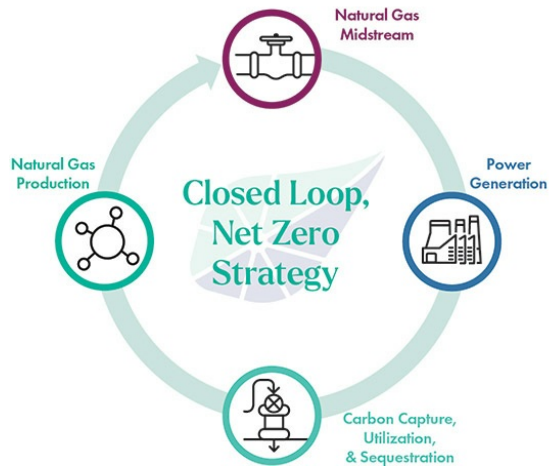
LNG is natural gas in its liquid phase after being super-cooled to-260°F. LNG is primarily used to store and transport gas between markets that have limited natural gas pipeline connectivity. Once natural gas is delivered to an LNG facility, the gas is liquified and shrunken to approximately 1/600th of its original volume. Then, the LNG is loaded onto carriers that have large cryogenic tanks onboard for oceanic transport. At receiving terminals, the LNG is transitioned back into its original gaseous state. From there, the regassified gas is either stored or transported via pipeline to end-consumers like power plants, industrial facilities, and residential communities.

In the wake of the Russian invasion of Ukraine, Russia’s steep gas supply cuts to the EU put pressure on European and global gas markets. According to the EIA, before Russia’s piped natural gas exports to the EU declined by an estimated 49% year-over-year in 2022, close to 40% of total EU gas demand was sourced from Russia. To mitigate that shortfall, European LNG imports increased by 65% compared to 2021, according to the EIA, which also reported that U.S. LNG exports to Europe increased by 141% over the same period, representing 64% of all U.S. LNG exports in 2022. According to the EIA and FERC, because U.S. LNG utilizations are at all-time highs at 98% of baseline capacity, an additional 11.9 Bcf/d capacity is currently under construction, and another 19.1 Bcf/d in capacity has been approved by FERC. Current market dynamics have poised LNG for expansion, particularly in the U.S. Gulf Coast, where approximately 90% of the U.S. LNG build is slated, according to FERC. The Barnett region is approximately 300 miles from the Gulf Coast LNG market. Producers are capitalizing on these dynamics by entering into supply agreements that provide a take-or-pay style fixed liquefaction fee for the LNG facility and efficient access to the global gas markets. Upstream producers with exposure to international LNG natural gas prices are expected to provide a baseline of pricing support for Texas and Louisiana-based natural gas producers with pipeline connectivity to the Gulf Coast.

BUSINESS

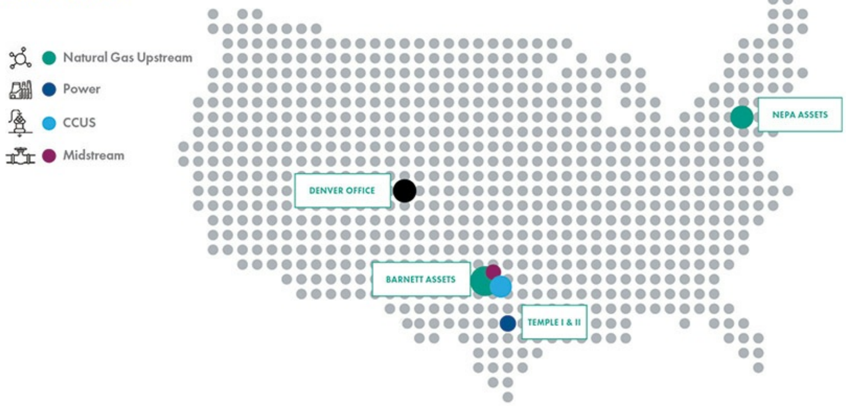
Overview

We are a forward thinking, growth driven energy company focused on creating value for our stockholders through the organic development of our properties as well as accretive acquisitions. Our core business is to produce natural gas from our owned and operated upstream businesses, which are supported by our four business lines: natural gas production; natural gas gathering, processing and transportation (our “natural gas midstream business”); power generation; and carbon capture, utilization and sequestration (“CCUS”). We expect our owned and operated upstream and natural gas midstream businesses to achieve net zero Scope 1 and Scope 2 emissions by the early 2030s, and net zero Scope 1, 2 and 3 emissions by the late 2030s. We maintain a “closed-loop” approach to our net zero emissions goal through the operation of our four business lines. We are committed to vertically integrating portions of our business to reduce costs and improve overall commercial optimization of the full value chain. For instance, in the Barnett, our natural gas production is gathered and transported in part through our midstream systems and we commenced sequestration operations at our first CCUS project in November 2023. We expect our second CCUS project to commence sequestration activities in the first half of 2026 and are evaluating a robust backlog of actionable CCUS opportunities. We believe that our differentiated business model, net zero emissions focus, highly experienced management team and technology-driven approach to operating our business will enable us to create stockholder value.



We understand the impact climate change has on our community, the world and future generations, which is why addressing these impacts in how energy is produced is a top priority. In particular, it is one of our core values, “Be One BKV,” to create a unified team with a shared vision to achieve our emission reduction and energy impact goals.

BKV Assets



Overview of BKV Assets

Natural Gas

	Net Production (MMcfe/d)	SEC 1P Reserves (Tcfe)	Producing Wells[1]	Net Acres
	Year Ended December 2023	As of December 2023	As of December 2023	As of December 2023
Barnett	718	3.7	6,614	460,000
NEPA	142	0.4	414	37,000
Total	860	4.1	7,028	497,000

Operated Midstream

	As of December 2023 Throughput (MMcf/d)	Pipeline Miles	Midstream Compressors
Barnett	233	778	65

Power

	Location	Heat Rate Btu/kWh	Capacity MW+
Temple I	Bell County, TX	6,904	752
Temple II	Bell County, TX	6,950	747

CCUS

Projects in Operation	Status	Initiation of Sequestration Operations	Forecasted Annual Sequestration Volumes (Mtpy CO_2e)[4]
Barnett Zero	Operating	November 2023	0.18
Potential Projects	**Status[2]**	**Forecasted Initiation of Sequestration Operations[3]**	**Forecasted Annual Sequestration Volumes (Mtpy CO_2e)[4]**
Cotton Cove	FID	1H 2026	0.04
8 NGP Projects	Pre-FID	2025-2029	2.68
3 Industrial Projects	Pre-FID	2026-2027	11.15
4 Ethanol Projects	Pre-FID	2027-2029	2.56

(1) Includes producing wells in which BKV has an ORRI or Non-Operated Interest.

(2) We have not secured external financing, reached FID or entered into the definitive agreements necessary to execute any of the pre-FID projects identified above.

(3) Our projected timeline for commencement of sequestration operations at the Cotton Cove Project and all of the pre-FID projects identified above depends in part on our ability to fund the capital requirements for these potential projects through external funding and revenues from our upstream business, as well as a regulatory environment that is favorable to our projects and their development. See *Risk Factors—Risks Related to our CCUS Business*.

(4) We may not receive 100% of the environmental attributes associated with CCUS projects funded in whole or in part by third parties, and, in such cases, we expect to have the right to purchase such environmental attributes BKV would not otherwise receive. Ultimately, we will be able to apply only such portion of the sequestered emissions to offset our own GHG emissions that corresponds to the percentage of environmental attributes BKV receives or purchases.

Our Operations

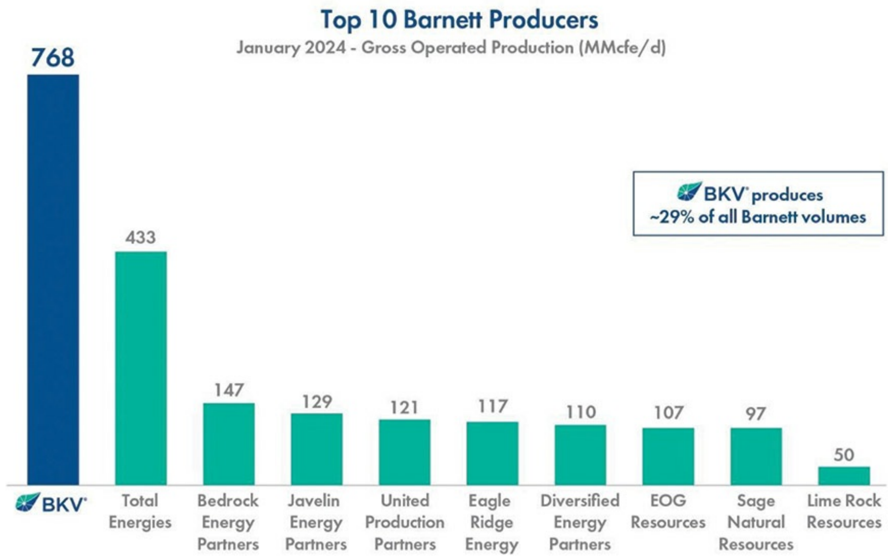
Natural Gas Production

We are engaged in the acquisition, operation and development of natural gas and NGL properties primarily located in the Barnett and in NEPA. Our upstream assets are the core of our business and provide us with substantial Adjusted Free Cash Flow, which we expect will be sufficient to fund our upstream, midstream and power capital expenditure program while maintaining a conservative balance sheet. We have a balanced portfolio of low decline producing properties and undeveloped inventory, primarily in the Barnett. Additionally, our focus on operational efficiencies, access to BKV-owned and third-party midstream systems, and proximity to natural gas demand markets along the Gulf Coast and Northeast corridor allow us to generate high margins.

As of June 30, 2024, our total acreage position was approximately 479,000 net acres, 99% of which was held by production. For the six months ended June 30, 2024, our net daily production averaged 807.6 MMcfe/d, consisting of approximately 80% natural gas and approximately 20% NGLs. As of December 31, 2023, our total proved reserves of 4,094 Bcfe had an estimated 8.1% year-over-year average base decline rate over the next 10 years. We have more than 15 years of core development inventory, with attractive returns, based on a 1 to 1.5 rigs per year pace, including 535 gross drilling locations, of which 99 are proved locations, and 2,097 gross refrac candidates, of which 501 are proved locations. For a discussion of how we identify drilling locations and refrac candidates, please see "*— Our Operations — Natural Gas Production — Determination of Identified Drilling and Refracture Locations*." Based on current commodity prices, the capital investment required to hold production flat year-over-year is equal to less than approximately 60% of our Adjusted EBITDAX for the 2023 fiscal year. Adjusted EBITDAX is not a financial measure calculated in accordance with GAAP. See "*Prospectus Summary — Summary Historical Financial Information — Non-GAAP Financial Measures*" for a description of this measure and a reconciliation to the most directly comparable GAAP measure.

We entered the Barnett in October 2020 with our acquisition of the 2020 Barnett Assets from Devon Energy. On June 30, 2022, we further scaled our Barnett position by acquiring approximately 165,000 net acres, 2,100 operated wells and related upstream, midstream and other assets in the Exxon Barnett Acquisition. As of June 30, 2024, our Barnett acreage position was approximately 460,000 net acres, which is approximately 99% held by production. Our average daily Barnett production of approximately 682.5 MMcfe/d for the six months ended June 30, 2024 consisted of approximately 76% natural gas and approximately 24% NGLs. We had an average working interest in our operated wells in the Barnett of approximately 96.9% as of December 31, 2023 and an Effective NRI in the Barnett of approximately 80.2%.

We are the largest natural gas producer by gross operated volume in the Barnett. Based on information published by the TRRC, the chart below illustrates our gross operated production volumes in the Barnett as of January 2024, which represent approximately 29% of the total Barnett production, and nearly double than that of the next largest producer in the Barnett for the month of January 2024.



We entered NEPA in 2016 and have subsequently scaled our position through 12 acquisitions. As of June 30, 2024, our acreage position was approximately 19,480 net acres, which is approximately 97.5% held by production. Our average net daily production of 125.2 MMcfe/d for the six months ended June 30, 2024 consisted entirely of natural gas. We had an average working interest in our operated wells in NEPA of 89.4%, as of December 31, 2023.

On June 14, 2024, we sold our wholly owned subsidiary, BKV Chaffee, which owned a non-operated interest in approximately 9,800 net acres and 116 gross (24.2 net) wells and approximately 122 Bcfe of proved reserves in NEPA, as well as our interest in the Repsol Oil & Gas operated midstream system, for a purchase price of $106.7 million, subject to adjustment. On June 28, 2024, our wholly owned subsidiary, BKV Chelsea, sold certain of its non-operated upstream assets, including its interest in approximately 6,800 net acres and 214 gross (15.4 net) wells and approximately 35 Bcfe of proved reserves in NEPA for a purchase price of $25.0 million, subject to adjustment.

In February 2023, we re-certified most of our production under the TrustWell environmental assessment program of Project Canary, an environmental certification and ESG data company. We achieved a Gold rating from Project Canary, the second highest rating a company can receive for its production, qualifying the certified portion of our natural gas production as RSG. As part of its environmental assessment, Project Canary analyzes and certifies our production on a well by well basis. As of June 30, 2024, approximately 70% of our NEPA production and approximately 45% of our Barnett production was re-certified. We intend to continue an environmental assessment of substantially all of our existing production. In addition, we intend to advance the market for our produced gas beyond RSG and its current certification towards "Carbon Sequestered Gas", a Scope 1, 2 and 3 carbon neutral natural gas product. We expect that production of Carbon Sequestered Gas will be achieved by bundling RSG with carbon credits sufficient to offset the estimated emissions associated with the production, gathering and boosting of such RSG, as well as the estimated emissions from its transmission, distribution (if applicable) and ultimate combustion, with the quantified emissions and the requisite volume of CCUS offsets being third-party certified. We have an agreement with a third party to establish the blockchain ledger and tokens; however, this process is dependent upon the development of the necessary technology by such third party. In addition, we expect to utilize the blockchain ledger and tokens with the American Carbon Registry, once that registry has been established. The carbon credits included in our Carbon Sequestered Gas will be generated by our CCUS projects, as described below in "— *Path to Net Zero Emissions*" and retired against our Scope 1 and/or Scope 3 emissions.

We believe Carbon Sequestered Gas could potentially provide a decarbonized, certified and qualified fuel and retired credits bundle that is a differentiated and premium product.

In August 2023, BKV entered into a contract with ENGIE Energy Marketing NA, Inc, a subsidiary of global energy utility ENGIE, for the sale and purchase of up to 10,000 MMBtu/d of our Carbon Sequestered Gas. Additionally, in March 2024, BKV entered into a contract with Kiewit Infrastructure South Co., a subsidiary of Kiewit, for the sale and purchase of up to 100 MMBtu/d of our Carbon Sequestered Gas. The carbon credits included in our Carbon Sequestered Gas will be generated by our CCUS projects and will be third-party verified. Subject to completion of our certification process with the American Carbon Registry (see "— *Carbon Capture, Utilization and Sequestration*" below), we expect to begin delivery of Carbon Sequestered Gas by the end of 2024.

Natural Gas Midstream

Through our ownership in midstream systems, we are engaged in the gathering, processing and transportation of natural gas (which we refer to as our natural gas midstream business) that supports our upstream assets and third-party producers in the Barnett and NEPA. Our midstream assets improve our overall corporate returns by enhancing our margins and lowering our break-even operating costs while allowing us to manage the timing, development and optimization of production of our upstream assets. In the Barnett, during the six months ended June 30, 2024, approximately 193 MMcf/d of our gross production (approximately 22% of our total gross Barnett production) was gathered and processed by our owned Barnett midstream system, which includes approximately 778 miles of gathering pipeline, 65 midstream compressors and one amine processing unit. Additionally, our owned Barnett midstream system has over 200 MMcf/d in unutilized pipeline and processing capacity, providing room to increase throughput (from our own production and for third-party volumes) while maintaining optimal operating pressure with limited additional capital investment required. We also believe we have ample dedicated capacity on third party midstream systems for our expected production and future development. We own and operate approximately 16 miles of natural gas gathering pipelines, 14 miles of freshwater distribution pipelines and six gas compression units in NEPA. As part of our sale of BKV Chaffee, we sold our minority non-operated ownership interest in a Repsol Oil & Gas operated midstream system in NEPA on June 14, 2024.

Power Generation

We have a 50% ownership interest in the BKV-BPP Power Joint Venture, which owns the Temple Plants, modern combined cycle gas and steam turbine power plants located in the ERCOT North Zone in Temple, Texas. The remaining 50% interest is owned by BPPUS, a wholly owned subsidiary of Banpu Power and an affiliate of our sponsor, Banpu. Temple I and Temple II have annual average power generation capacities of 752 MW and 747 MW, respectively, and each power plant delivers power to customers on the ERCOT power network in Texas. Temple I and Temple II have baseload design heat rates of approximately 6,904 Btu/kWh and 6,950 Btu/kWh, respectively, which are below the ERCOT CCGT average. The modern technology utilized at the Temple Plants enables them to respond to rapidly changing market signals in real time, ensuring the highest operational readiness during the time when electricity consumption peaks (in winter and summer), making the power plants well-suited to serve the various needs of the ERCOT market. We continue to explore potential additional acquisitions to expand our power generation business. We expect our power generation assets will be synergistic with our base upstream business and we leverage our existing organization to provide marketing, engineering, finance, accounting and other administrative services to the BKV-BPP Power Joint Venture for an annual fee plus expenses.

In addition, after receiving the necessary approvals from the PUCT and ERCOT, the BKV-BPP Power Joint Venture recently launched a retail marketing business to sell electricity to commercial, industrial, and residential retail customers in Texas through its wholly owned subsidiary, BKV-BPP Retail, under the brand name BKV Energy. Since its official launch in February 2023, BKV Energy has built a portfolio of over 57,000 customers and is licensed to serve throughout the deregulated portions of Texas.

Carbon Capture, Utilization and Sequestration

Through our CCUS business, we aim to reduce man-made GHG emissions to the atmosphere by capturing CO_2 emitted in connection with natural gas activities, whether from our own operations or third-party operations, as well as from other energy and industrial sources. Our process involves capturing CO_2

before it is released into the atmosphere and then compressing the captured CO_2 and transporting it via pipeline to sites where it can be injected into UIC wells for secure geologic sequestration. Additionally, we have engaged Project Canary to analyze and report the CO_2e injection volumes and environmental attributes of our sequestration projects, and we are working with the American Carbon Registry to certify and register the environmental attributes associated with our CCUS projects as tradeable carbon credits. In the future, we may sell carbon credits associated with our CCUS projects to unrelated third parties outside of our value chain, which may negatively impact our net zero strategy, including by delaying or preventing our achievement of net zero.

Although we formally launched our CCUS business in March 2022 with the establishment of BKV dCarbon Ventures, we have been evaluating project opportunities and developing our CCUS business since early 2021. The development of our CCUS business has progressed rapidly, supported by internal geology, engineering, operations, business development, land, regulatory and other professionals, along with academics and CCUS-focused partnerships. We believe that with a continued and timely execution of our business plans, the Barnett Zero Project could begin generating positive net income via tax credits in 2024. We expect to fund up to 50% of our CCUS business from a variety of external sources, which may include joint ventures, project-based equity partnerships and federal grants, with the remaining capital needs being funded with cash flows from operations. The projected timeline for commercial operations and the generation of positive CCUS business revenue and positive earnings depends, in part, on our ability to fund the anticipated capital requirements for the potential projects that we have identified and described below through external funding and revenues from our upstream business, as well as on our ability to receive our portion of the anticipated Section 45Q tax credits associated with these projects. We may not receive 100% of the Section 45Q tax credits associated with projects funded by third parties and, in such cases, will receive only a corresponding percentage of the anticipated Section 45Q tax credits associated with such projects.

We seek to execute CCUS projects with attractive standalone economics and the ability to sequester emissions from both our own operations and from third-party operations. For example, we plan to target CCUS projects with high concentration CO_2 streams where revenue, taking into account tax incentives, less cash operating expense would generally be expected to be between \$40 and \$70 per metric ton of sequestered CO_2e for the first six years of commercial operations for projects owned by BKV. We may also provide development and support services for third-party owned CCUS projects on a fee-for-service model, although such projects will not be included in our path to net zero. We are also evaluating potential third party investments in our CCUS business, which may accelerate the development of our CCUS projects; however, depending on the terms of such investment, this may impact the ultimate number of carbon credits we may receive from such projects.

As part of our "closed-loop" approach to our net zero emissions goal, we expect to apply a portion of the CO_2 emissions that are sequestered through our CCUS business to offset GHG emissions from our owned and operated upstream and natural gas midstream businesses. We may not receive 100% of the environmental attributes associated with CCUS projects funded in whole or in part by third parties, and, in such cases, we expect to have the right to purchase such environmental attributes BKV would not otherwise receive. Ultimately, we will be able to apply only such portion of the sequestered emissions to offset our own GHG emissions that corresponds to the percentage of environmental attributes BKV receives or purchases. We expect our CCUS business to contribute in significant part to our goals to fully offset our Scope 1 and 2 emissions from our owned and operated upstream and natural gas midstream businesses by the early 2030s, and our Scope 1, 2 and 3 emissions from our owned and operated upstream and natural gas midstream businesses by the late 2030s. See "*— Path to Net Zero Emissions*" below for a description of how we estimate our Scope 1, 2 and 3 annual emissions and how we expect our CCUS business to contribute to the offset of those emissions.

CCUS Projects

Currently, we have one operational CCUS project and are pursuing sixteen additional potential CCUS projects that we believe are commercially viable based on economics supported by enhanced Section 45Q tax credits and that we believe can be completed by the late 2030s. We have entered into various letters of intent and definitive contracts that we expect to grant us carbon storage and sequestration rights on over 44,000 acres of leased pore space across seven distinct projects located in three states, with total reservoir storage capacity of over 1 billion metric tons of CO_2e. We have filed applications to seek Class VI permits for two of these pore space locations, one of which is in the State of Louisiana. The EPA recognized our permit applications as being administratively complete in January 2024 and February 2024, respectively, and then transferred our permit application applicable to the Louisiana pore space location to the State of Louisiana, which assumed primacy for Class VI well permitting. The Louisiana Department of Energy and Natural Resources declared our permit application administratively complete in July 2024. The EPA expects to complete its technical review of our other permit application by September 2025. Our projected timeline for commercial operations of these sixteen projects depends in part on our ability to fund the capital requirements for these potential projects through external funding and revenues from our upstream business. Our timeline also depends on a regulatory environment that is favorable to our projects and their development. Our potential projects can be placed into six categories: (i) operational projects, (ii) projects that have reached FID, but are not yet operational, (iii) identified NGP projects under evaluation, (iv) identified industrial projects under evaluation, (v) identified ethanol projects under evaluation, and (vi) other potential projects that have been identified but not yet sufficiently evaluated. We have achieved notable milestones with respect to several of the seventeen projects within the first five categories, as more fully described below.

Project	Status[(1)]	Actual or Forecasted Initiation of Sequestration Operations[(2)]	Forecasted Annual Sequestration Volumes (Mtpy CO_2e)[(3)]
Barnett Zero	Operating	November 2023	0.18
Cotton Cove	FID	1H 2026	0.04
8 NGP Projects	Pre-FID	2025 – 2029	2.68
3 Industrial Projects	Pre-FID	2026 – 2027	11.15
4 Ethanol Projects	Pre-FID	2027 – 2029	2.56

(1) We have not secured external financing, reached FID or entered into the definitive agreements necessary to execute any of the pre-FID projects identified above.

(2) Our projected timeline for commencement of sequestration operations at the Cotton Cove Project and all of the pre-FID projects identified above depends in part on our ability to fund the capital requirements for these potential projects through external funding and revenues from our upstream business, as well as a regulatory environment that is favorable to our projects and their development. See "*Risk Factors — Risks Related to Our CCUS Business.*"

(3) We may not receive 100% of the environmental attributes associated with CCUS projects funded in whole or in part by third parties, and, in such cases, we expect to have the right to purchase such environmental attributes BKV would not otherwise receive. Ultimately, we will be able to apply only such portion of the sequestered emissions to offset our own GHG emissions that corresponds to the percentage of environmental attributes BKV receives or purchases.

Operational Projects

Barnett Zero Project. In November 2023, our first CCUS project, which we refer to as the Barnett Zero Project, commenced commercial sequestration of CO_2 waste generated by EnLink's Bridgeport natural gas processing plant and neighboring operations. In the Barnett Zero Project, EnLink transports our natural gas produced in the Barnett to its natural gas processing plant in Bridgeport, Texas, where the CO_2 waste stream is captured, compressed and then disposed of and sequestered via our nearby injection well. The Barnett Zero Project is an NGP project that separates CO_2 from substantially all of our EnLink-gathered natural gas production. We initially reached FID and entered into a definitive agreement with EnLink for the Barnett Zero Project in June 2022, subsequently drilled a Class II well that complies with standards applicable to Class VI wells, obtained EPA-approval of our Monitoring, Reporting and Verification Plan, as required by the EPA's Greenhouse Gas Reporting Program, and commenced operations with first injection in November 2023. We expect the Barnett Zero Project to achieve an average sequestration rate of approximately 183,000 metric tons of CO_2e per year and to require a total investment by us of approximately $36.0 million, of which $34.0 million has been invested as of December 31, 2023.

We intend to use the Barnett Zero Project as a prototype for modular NGP projects that can be repeated and quickly scaled. We are currently progressing eight NGP projects based on this model and anticipate that these projects will reach FID at various points in 2025 through 2029.

FID Projects

Cotton Cove Project. On October 18, 2022, BKV dCarbon Ventures reached internal FID to develop our second CCUS project in the Barnett. This CCUS project, which we refer to as the Cotton Cove Project, will separate, dispose of and geologically sequester CO_2 generated as a byproduct of our natural gas production in the Barnett and will utilize our midstream assets to do so. We have multiple pore space opportunities for CO_2 injection, and we estimate the Cotton Cove Project will geologically sequester up to approximately 40,000 metric tons of CO_2 per year, and we expect to be entitled to use 100% of the environmental attributes associated with such volumes towards our net zero goals. The Cotton Cove Project is held through BKV-BPP Cotton Cove LLC ("BKV-BPP Cotton Cove" or the "BKV-BPP Cotton Cove Joint Venture"), a joint venture owned 51% by BKV dCarbon Ventures and 49% by BPPUS. We currently estimate the total investment required for the Cotton Cove Project to be approximately $17.6 million, of which we will be required to contribute approximately $9.0 million and under the terms of an agreement with BPPUS, we expect to be entitled to use 100% of the environmental attributes associated with such volumes towards our net zero goals. We are targeting commencement of CO_2 sequestration activities in the first half of 2026, subject to our ability to secure all required permits, at which point we expect this project will be the second of our current modular line of identified potential NGP projects, in addition to the Barnett Zero Project. Additionally, BKV dCarbon Ventures will manage the BKV-BPP Cotton Cove Joint Venture and leverage our existing organization to provide marketing, engineering, finance, operations, project management, accounting and other administrative services to the BKV-BPP Cotton Cove Joint Venture, in each case for an annual fee plus expenses. For additional information about the BKV-BPP Cotton Cove Joint Venture, see "*Certain Relationships and Related Party Transactions — BKV-BPP Cotton Cove Joint Venture — BKV-BPP Cotton Cove Limited Liability Company Agreement*."

We are also evaluating expansion of the Barnett Zero and Cotton Cove Projects to pilot, and then scale, post-combustion carbon capture technology that would allow us to sequester up to an additional approximately 250,000 metric tons per year of captured CO_2e from low concentration emissions from within our natural gas midstream and/or other nearby processing operations. As part of this process, we intend to capture CO_2e from sources such as compressor exhaust flues and utilize compressor waste heat to reduce energy requirements and cost.

NGP Projects

We have identified eight potential NGP projects that we anticipate will achieve FID and commence initial sequestration operations at various points in 2025 through 2029. If approved and implemented, we anticipate that these eight projects would sequester third-party emissions, require a total capital investment by us of approximately $440.0 million by December 31, 2029 and thereafter provide a combined forecasted annual sequestration volume of approximately 2.68 million metric tons per year of captured CO_2e.

A significant portion of the carbon capture infrastructure necessary to execute these eight potential NGP projects already exists. For example, we entered into definitive agreements for pore space leasehold that would provide approximately 45 million metric tons of CO_2e sequestration capacity for one project, and, in connection with our development of another project, entered into a definitive agreement with a local emitter for the transfer and purchase of the CO_2 waste stream from its natural gas processing plant. Therefore, if approved at FID, and assuming we are able to execute definitive agreements on the terms and timeline we believe are obtainable and secure sufficient external funding, we expect these projects to start sequestration operations before December 31, 2029.

Industrial Projects

We are currently evaluating three potential medium to higher concentration industrial projects to sequester third-party emissions, which we anticipate will achieve FID and commence initial sequestration operations at various points in 2026 through 2027. If approved and implemented, these three projects would provide a combined forecasted annual sequestration volume of approximately 11.15 million metric tons per year of captured CO_2e.

Pore space leaseholds have been secured for all three of these projects, including one covering approximately 21,000 acres of state-owned land in Louisiana, which project we refer to as the High West Project.

In August 2023, High West, a wholly owned subsidiary of BKV dCarbon Ventures, entered into a carbon sequestration agreement with the State of Louisiana to develop facilities and permanently sequester CO_2 from local third-party emissions sources. The State of Louisiana granted High West the carbon storage and sequestration rights on approximately 21,000 acres of land in St. Charles and Jefferson Parishes. The acreage is in an ideal location for targeted carbon capture and sequestration efforts, with an estimated 22 Mtpy CO_2e of potential capture and sequestration located within a 20 mile radius from various emissions points. In addition, the storage site has a large CO_2 storage potential, estimated to be between 140 to 1,000 Mtpy CO_2, subject to further evaluation, planning and development design decisions. Under the agreement, High West will dispose of CO_2e waste from local third-party emissions sources through permanent sequestration via injection wells on the designated acreage. This project, which we refer to as the High West Project, is expected to reach FID by the end of 2024. BKV dCarbon Ventures engaged NuQuest Energy, LLC to provide CCUS marketing and development services for the High West Project.

We have filed applications to seek Class VI permits for two of these industrial projects, one of which is in the State of Louisiana. The EPA recognized our permit applications as being administratively complete in January 2024 and February 2024, respectively, and then transferred our permit application applicable to the Louisiana pore space location to the State of Louisiana, which assumed primacy for Class VI well permitting. The Louisiana Department of Energy and Natural Resources declared our permit application administratively complete in July 2024. The EPA expects to complete its technical review of our other permit application by September 2025. We also anticipate that a Class VI permit application for the third project will be submitted by August 2024. If each of these projects is approved at FID, and we are able to secure sufficient external financing and assuming definitive agreements are timely executed containing terms we believe are obtainable, we expect to initiate sequestration operations between 2026 and 2027. Verde CO2 has the option to purchase up to a 5% minority economic interest in two of these potential industrial projects and, to the extent it exercises such option, would be entitled to a pro rata share of the Section 45Q tax credits associated with the CCUS projects in which it invests.

Ethanol Projects

We have identified four potential ethanol projects that we anticipate will achieve FID and commence initial sequestration operations at various points during 2027 through 2029. If approved and implemented, we anticipate that these four projects would sequester third-party emissions, require a total capital investment by us of approximately $680 million by December 31, 2029, and thereafter provide a combined forecasted annual sequestration volume of approximately 2.56 million metric tons per year of captured CO_2e.

If each of these projects is approved at FID and assuming we are able to execute definitive agreements on the terms and timeline we believe are obtainable and secure sufficient external funding, we expect to begin sequestration operations between 2027 and 2029.

In addition to these sixteen identified potential projects, we are currently evaluating more than ten early-stage project opportunities that are aligned with our high concentration strategy but are not yet sufficiently evaluated to determine potential sequestration volumes, geologic feasibility or timeline of completion. We also evaluate later-stage opportunistic CCUS project acquisition opportunities. In the event a potential project listed above is not progressed for any reason, including failure to FID, or additional funding provides for greater capacity to complete projects, we may further evaluate and develop one or more of these early-stage project opportunities.

Our CCUS business of capturing and sequestering emissions from our operations and from operations of third parties is a critical component of our “closed-loop” approach to achieving our goal of net zero Scope 1 and 2 emissions from our owned and operated upstream and natural gas midstream businesses by the early 2030s and Scope 1, 2 and 3 emissions from our owned and operated upstream and natural gas midstream businesses by the late 2030s. We expect to continue to identify and evaluate additional CCUS projects and we believe that we will be able to complete a sufficient number of the above-described or other CCUS projects in order to meet our Scope 1, 2 and 3 emissions goals. See "— *Path to Net Zero Emissions*" for a more detailed description of how we anticipate reaching our Scope 1, 2 and 3 emissions goals.

However, we have not secured external financing, reached FID or entered into the definitive agreements necessary to execute any of the pre-FID projects identified above, and there can be no guarantee that we will be able to execute and operate any of the sixteen identified potential CCUS projects (or any other CCUS projects) with sufficient volumes of CO_2e sequestration to achieve our Scope 1, 2 and 3 emissions goals on the timelines we anticipate. There can be no assurance that any of the sixteen identified CCUS projects discussed above, the Barnett Zero Project or any other CCUS project will achieve the forecasted sequestration volumes, and we may not commence sequestration operations for any of the projects identified above by the anticipated timeframe, or at all. Furthermore, we may not receive 100% of the environmental attributes associated with CCUS projects funded in whole or in part by third parties, and, in such cases, we expect to have the right to purchase such environmental attributes BKV would not otherwise receive. Ultimately, we will be able to apply only such portion of the sequestered emissions to offset our own GHG emissions that corresponds to the percentage of environmental attributes BKV receives or purchases. While we may consider alternatives to offset our owned and operated upstream and natural gas midstream emissions (including the purchase of verified offset credits) in order to meet our Scope 1, 2 and 3 emissions goals, ultimately, we may not be able to achieve our goals of net zero Scope 1 and 2 emissions from our owned and operated upstream businesses and natural gas midstream by the early 2030s or net zero Scope 1, 2 and 3 emissions from our owned and operated upstream businesses and midstream businesses by the late 2030s.

We estimate the aggregate investment required to develop the seventeen identified actual and potential CCUS projects to be between approximately $1.3 – 1.8 billion between now and the end of 2030. We anticipate that some of these project costs will be borne by third-party investors in these projects, including owners of sources of CO_2e, landowners and other stakeholders. In order to achieve the projected timeline for commercial operations of such projects, we expect to fund the anticipated cost of these CCUS projects with a combination of up to 50% from third party sources, which may include joint ventures, project-based equity partnerships and federal grants, with the remaining capital needs being funded with cash flows from operations. We are able to moderate the capital required to fund our CCUS business, as our CCUS business model provides flexibility for us to selectively invest in only the sequestration component of a project or in the capture, transportation and sequestration components, depending on the scope of the project. Therefore, if sufficient external funding is not available, then we would expect to continue to develop our CCUS business from cash flows from operations on a less accelerated timeline, which may result in an inability to achieve our Scope 1, 2 and 3 emissions goals on the timeline we anticipate.

Our CCUS business and all of our CCUS projects are in the early stages of development. Although we commenced commercial operations with the initial injection of CO_2 waste at the Barnett Zero Project on November 13, 2023, and have reached FID and entered into definitive agreements with respect to the Cotton Cove Project, we have not reached FID with respect to or entered into the definitive agreements necessary to execute any of the other fifteen potential projects identified above. We may not be able to reach agreements on terms acceptable to us or achieve our projected timeline for commercial operations for these projects. In addition, the development of our CCUS business is expected to require material capital investments, and the projected timeline for commercial operations depends on our ability to fund the anticipated capital requirements for the potential projects that we have identified through external funding and revenues from our upstream business. Furthermore, the commercial viability of our CCUS projects depends, in part, on obtaining necessary permits and other regulatory approvals and on our ability to receive our portion of the anticipated Section 45Q tax credits associated with these projects. In particular, we must meet certain wage and apprenticeship requirements in order to qualify for enhanced Section 45Q tax credits. For more information about the risks involved in our CCUS business, see "*Risk Factors — Risks Related to Our CCUS Business.*"

To help us achieve our goal of becoming a leader in CCUS, we established a steering committee that includes two engineers renowned for their work in the development of CCUS projects: Dr. Paitoon (P.T.) Tontiwachwuthikul (Professor of Industrial & Process Systems Engineering & Fellow, Canadian Academy of Engineering) and Dr. Malcolm A. Wilson (Program Director, CO2 Management, Office of Energy & Environment (OEE), Adjunct Professor of Engineering and Graduate Studies). These individuals are professors at the University of Regina, a leading carbon capture research institution, and each has been engaged in CCUS for over 30 years.

Path to Net Zero Emissions

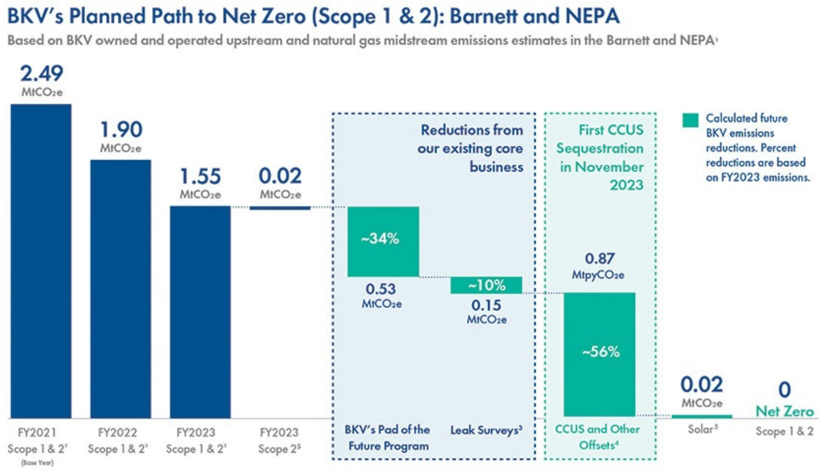
We conducted an initial assessment of our annual Scope 1 and 2 emissions from our owned and upstream businesses as of December 31, 2021, and subsequently updated that assessment for the upstream and natural gas midstream businesses acquired through the Exxon Barnett Acquisition in 2022 to establish an emissions baseline of 2.49 Mtpy CO_2e annual Scope 1 and 2 emissions from our owned and operated upstream and natural gas midstream businesses as of December 31, 2021. Our assessments did not address our GHG emissions from our other business operations.

We have made progress in the reduction of our annual Scope 1 and 2 emissions from our owned and operated upstream and natural gas midstream businesses since December 31, 2021. We estimate that our Scope 1 and 2 annual emissions from our owned and operated upstream and natural gas midstream businesses were approximately 1.9 Mtpy CO_2e as of December 31, 2022 and 1.55 Mtpy CO_2e as of December 31, 2023, reflecting a reduction of approximately 0.9 Mtpy CO_2e from our baseline emissions assessment established as of December 31, 2021. This reduction is due primarily to the implementation of our "Pad of the Future" and leak detection and repair programs, which began in the fourth quarter of 2021 and occurred throughout 2022 and 2023. During this time frame, our "Pad of the Future" program has eliminated 0.52 Mtpy CO_2e, or 21%, of our annual Scope 1 and 2 emissions from our owned and operated upstream and natural gas midstream businesses, and improvements in our emission quantification methods and the implementation of site-level leak detection and repair programs have resulted in the elimination of an additional 0.42 Mtpy CO_2e, or 17%, of our annual Scope 1 and 2 emissions from our owned and operated upstream and natural gas midstream businesses. In total, this represents a 0.94 Mtpy CO_2e or 38% reduction of our annual GHG emissions from our baseline emissions assessment established as of December 31, 2021.

Our emissions estimates presented in this prospectus are based on information with respect to our owned and operated upstream and natural gas midstream businesses in the Barnett and NEPA through fiscal year 2023 and reported by BKV pursuant to the Subpart C and Subpart W, as applicable, requirements of the federal Clean Air Act GHG reporting program regulations of the EPA. These estimates will be updated annually to reflect any changes in activity, inventory, production throughput and emissions reduction retrofits or equipment modifications.

We estimate that our annual Scope 3 emissions from our owned and operated upstream and natural gas midstream businesses were approximately 18.7 Mtpy CO_2e as of December 31, 2023. These Scope 3 emissions are currently estimated in accordance with IPIECA's "Sustainability reporting guidance for oil and gas industry," dated March 2020. Specifically, Scope 3 emissions are estimated per the Greenhouse Gas Protocol's "Corporate Value Chain (Scope 3) Accounting and Reporting Standard," released in 2011, under Category 11 (Use of Sold Product). Scope 3 emissions estimated using source Category 11 represent the majority of Scope 3 emissions from our owned and operated upstream and natural gas midstream operations, with minor contributions from other source categories. Additionally, our estimated Scope 3 emissions calculations assume that all natural gas produced is combusted and does not account for other potential end uses of natural gas. Scope 3 mass emissions are calculated using the EPA's prescribed emissions factors for the speciated natural gas (methane and ethane) as well as NGLs assuming Y-grade NGLs. CO_2e emissions are estimated using AR4 Global Warming Potentials, similar to those used by the EPA. Our projected annual Scope 3 CO_2e emissions are estimated at an approximated year-end net production volume of 942 MMcfe/d of natural gas (approximately 85% methane, 5% ethane and 10% other) and approximately 139.4 MBbls of NGLs (or approximately 2 MMcfe/d), as reported to the EPA for Subpart W. Our NGL constituents are estimated based on average constituent NGL barrel. Allocating the entire 944 MMcfe/d towards combustion as the end use, applying suitable combustion emission factors from the EPA, and using AR4 GWPs, Scope 3 annual emissions from our owned and operated upstream operations are estimated to be approximately 18.7 Mtpy CO_2e. We currently engage third party consultants to develop and review our Scope 3 emissions estimates.

The charts below reflect (i) our estimated annual Scope 1 and 2 emissions from our owned and operated upstream and natural gas midstream businesses as of December 31, 2023, and (ii) our estimated annual Scope 3 emissions from our owned and operated upstream and natural gas midstream businesses as of December 31, 2023. These two charts also reflect our intended path to net zero Scope 1 and 2 emissions by the early 2030s and net zero Scope 1, 2 and 3 emissions by the late 2030s, in each case, for our owned and operated upstream and natural gas midstream businesses. These charts do not address our GHG emissions from our other business operations. As part of our "closed-loop" approach to our emissions goals, we intend to achieve these goals through our "Pad of the Future" emissions reductions, reductions attributable to emissions monitoring and leak surveys, emissions offsets from the retirement of SRECs generated by the BKV-BPP Power Joint Venture's planned solar facility and executing CCUS projects to sequester our and third-party emissions.



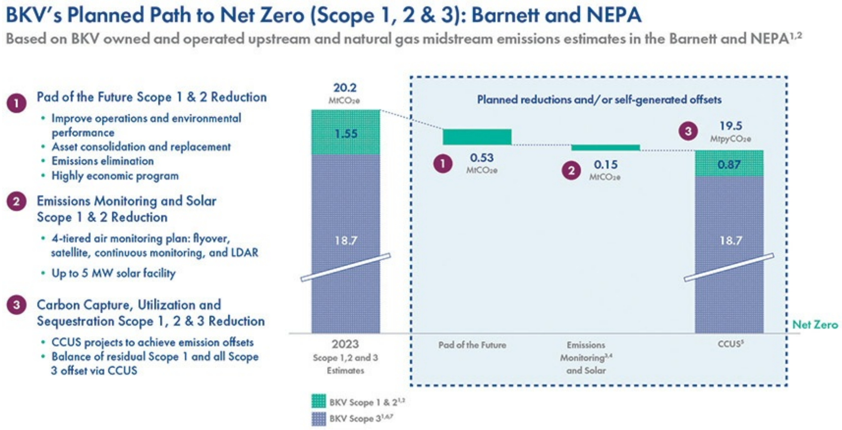
(1) These emissions estimates are based solely on our owned and operated upstream and natural gas midstream businesses. These emissions estimates do not reflect our GHG emissions from our other business operations, namely our CCUS operations and our power generation business through the BKV-BPP Power Joint Venture.

(2) Scope 1 calculated emissions are based on those reported to US EPA per Subpart W.

(3) Emissions surveys accomplished per US EPA Subpart W to reduce emissions.

(4) We achieved first injection of CO_2 waste at the Barnett Zero Project in November 2023.

(5) Retirement of the SRECs generated by the BKV-BPP Power Joint Venture's planned 2.5 MW to 5 MW solar facility is expected to offset up to 32% of current scope 2 emissions. The BKV-BPP Power Joint Venture has constructed a 2.5 MW solar facility, which will soon be operational and is in the process of obtaining permits for the remaining 2.5 MW. BKV expects to purchase the SRECs generated by the solar facility or will purchase off of the market to offset Scope 2 emissions.



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(1) These emissions estimates are based solely on our owned and operated upstream and natural gas midstream businesses. These emissions estimates do not reflect our GHG emissions from our other business operations, namely our CCUS operations and our power generation business through the BKV-BPP Power Joint Venture.

(2) Scope 1 and 2 calculated emissions are based on 791 MMscf/d production volume for 2023 Subpart W in the Barnett and 151 MMscf/d production volume for 2023 Subpart W in NEPA.

(3) Emissions surveys accomplished per US EPA Subpart W to reduce emissions.

(4) We achieved first injection of CO_2 waste at the Barnett Zero Project in November 2023.

(5) Retirement of the SRECs generated by the BKV-BPP Power Joint Venture's planned 2.5 MW to 5 MW solar facility is expected to offset up to 32% of current scope 2 emissions. The BKV-BPP Power Joint Venture has constructed a 2.5 MW solar facility, which will soon be operational and is in the process of obtaining permits for the remaining 2.5 MW. BKV expects to purchase the SRECs generated by the solar facility or will purchase off of the market to offset Scope 2 emissions.

(6) Scope 3 calculated emissions are based on an estimated net production rate of approximately 944 MMcfe/d (approximately 944 MMscf/d of natural gas and 2 MMscfe/day of NGLs) as reported to US EPA for CY 2023 Subpart W.

(7) Scope 3 calculated emissions are estimated assuming combustion-based usage of all produced natural gas and NGLs. Approximately 58% of NGLs are assumed to be combusted for fuel while 100% of all natural gas sold is assumed to be combusted for fuel. Scope 3 emissions estimation methodology is therefore considered to be conservative.

Planned Path to Net Zero (Scope 1 and 2)

Pad of the Future. Our "Pad of the Future" program implements pad level design improvements to reduce pad level usage of natural gas, reduce GHG emissions and maintain operational continuity. As of December 31, 2023, we had implemented elements of our "Pad of the Future" program on approximately 3,200 of our existing wells and we have successfully completed the implementation of the "Pad of the Future" program for our upstream owned and operated assets in NEPA. As a result, as compared to our 2021 baseline assessment, we have achieved a reduction in our estimated annual GHG emissions of approximately 0.53 Mtpy CO_2e. These reductions are calculated by using our pneumatic and other pad inventories, and such emissions are factored to be eliminated once the system has been converted from natural gas supplied to compressed air or electric.

We plan to implement elements of our "Pad of the Future" program on more than 6,000 of our existing wells (more than 16,500 pneumatic devices and 3,000 pneumatic pumps) by the end of 2027 for an aggregate estimated cost of approximately $35 to $40 million. Once this expansion is completed, we expect to eliminate approximately 1.0 Mtpy CO_2e of the currently estimated Scope 1 annual emissions from our owned and operated upstream and natural gas midstream businesses.

Emissions Monitoring and Solar. Our leak detection and repair emissions monitoring program involves continuous ground-based instrument monitoring, satellite-based monitoring, aerial flyovers and on the ground leak detection and repair inspections. In addition, we expect to purchase the SRECs generated by the BKV-BPP Power Joint Venture's planned 2.5 MW to 5 MW solar facility, which is scheduled to begin construction and generating power in 2024. The BKV-BPP Power Joint Venture has obtained permits for and is constructing 2.5 MW and is in the process of obtaining permits for the remaining 2.5 MW. Solar facilities may be subject to increasingly arduous regulatory requirements, including additional permitting requirements. For every 1,000 kilowatt-hours of electricity produced by an eligible solar facility, one SREC is awarded. For a solar facility to be credited with that SREC, the system must be certified and registered by state agencies. The BKV-BPP Power Joint Venture's planned solar facility is expected to generate SRECs to offset up to 32% of current GHG emissions. The SRECs BKV expects to purchase and retire are reflected in the charts above as neutralizing a portion of our annual Scope 2 emissions from purchased energy for our owned and operated upstream and natural gas midstream business.

CCUS. Further, as discussed under "— *Carbon Capture, Utilization and Sequestration*" above, we believe that the Barnett Zero Project, together with the Cotton Cove Project and the eight NGP projects, three industrial projects and four ethanol projects for the capture and sequestration of third-party emissions that we have identified, have a combined annual forecasted sequestration volume of approximately 16.61 Mtpy CO_2e by the end of 2029, which is greater than the approximately 0.87 Mtpy CO_2e annual Scope 1 and 2 emissions from our owned and operated upstream and natural gas midstream businesses that we currently estimate will remain after taking into account the expected emissions reductions and offsets from our "Pad of the Future" program, emissions monitoring and leak surveys and the retirement of SRECs generated by the BKV-BPP Power Joint Venture's planned solar facility that we expect to purchase. Although we have not secured external financing, reached FID or entered into the definitive agreements necessary to execute any of the eight NGP projects, three industrial projects or four ethanol projects we have identified, we expect these projects to reach FID and commence sequestration operations by the end of 2029. A significant portion of the carbon capture infrastructure necessary to execute the NGP projects already exists and, as discussed above, we continue to accomplish important milestones consistent with our projected timeline. If approved at FID, and assuming we are able to execute definitive agreements on the terms and timeline we believe are obtainable and secure sufficient external funding, we expect these projects to start sequestration operations before December 31, 2029.

If we are unable to complete these fifteen projects and the Cotton Cove Project before December 31, 2029, or enter into commercial agreements in connection with these projects that result in BKV receiving less than 100% of the associated emissions offsets, carbon credits or other environmental attributes, we may still reach our Scope 1 and 2 emissions goals with less than all of these projects completed, as the annual forecasted sequestration volume of (i) the Barnett Zero Project is 183,000 metric tons of captured CO_2e per year, (ii) the Cotton Cove Project is 40,000 metric tons of captured CO_2e per year, (iii) the eight potential NGP projects is an aggregate 2.68 million metric tons of captured CO_2e per year, (iv) the three potential industrial projects is an aggregate 11.15 million metric tons of captured CO_2e per year and (v) the four potential ethanol projects is an aggregate 2.56 million metric tons of captured CO_2e per year.

However, we have not secured external financing, reached FID or entered into the definitive agreements necessary to execute any of the pre-FID projects identified above, and there can be no guarantee that we will be able to execute and operate any of the sixteen identified potential CCUS projects (or any other CCUS projects) with sufficient volumes of CO_2e sequestration to achieve our Scope 1, 2 and 3 emissions goals on the timelines we anticipate. There can be no assurance that any of the potential projects we have identified or the Barnett Zero Project will achieve forecasted sequestration volumes, and we may not commence sequestration operations for any of the potential projects identified above by the anticipated timeframe, or at all. Furthermore, we may not receive 100% of the environmental attributes associated with CCUS projects funded in whole or in part by third parties, and, in such cases, we expect to have the right to purchase such environmental attributes BKV would not otherwise receive. Ultimately, we will be able to apply only such portion of the sequestered emissions to offset our own GHG emissions that corresponds to the percentage of environmental attributes BKV receives or purchases. While we may consider alternatives to offset our owned and operated upstream and natural gas midstream emissions (including the purchase of verified offset credits) in order to meet our Scope 1 and 2 emissions goals, ultimately, we may not be able to achieve our goals of net zero Scope 1 and 2 emissions from our owned and operated upstream businesses and natural gas midstream by the early 2030s.

Planned Path to Net Zero (Scope 1, 2 and 3)

We also aspire to offset the annual Scope 3 emissions impact of our owned and operated upstream and natural gas midstream businesses by the late 2030s, which we estimate to be approximately 18.7 Mtpy CO_2e annually as of December 31, 2023. Our CCUS business of capturing and sequestering our and third-party emissions is a critical component to achieving this net zero goal. This aspiration to offset the Scope 3 emissions of our owned and operated upstream and natural gas midstream businesses by the late 2030s is limited to our Category 11 (Use of Sold Product) emissions, which we believe represents a significant portion of the overall Scope 3 emissions from our owned and operated upstream and natural gas midstream businesses. However, our Scope 3 emissions estimate does not include our GHG emissions from our other business operations, namely our CCUS and power generation businesses.

As discussed in "— *Carbon Capture, Utilization and Sequestration,*" above, we are currently operating the Barnett Zero Project and have identified sixteen potential CCUS projects that we believe are commercially viable and estimate would have a combined forecasted annual volume of carbon capture and sequestration of approximately 16 Mtpy CO_2e, which represents approximately 79% of our current Scope 1, 2 and 3 annual emissions from our owned and operated upstream and natural gas midstream businesses, and represents approximately 82% of our current Scope 1, 2 and 3 annual emissions from our owned and operated upstream and natural gas midstream businesses after taking into account the expected emissions reductions and offsets from our "Pad of the Future" program, emissions monitoring and leak surveys and the retirement of SRECs generated by the BKV-BPP Power Joint Venture's planned solar facility that we expect to purchase. In addition, we are currently evaluating more than ten early-stage project opportunities that are aligned with our high concentration strategy and have been identified, but are not yet sufficiently evaluated to determine potential sequestration volumes, geologic feasibility or timeline of completion. We also evaluate later-stage opportunistic CCUS project acquisition opportunities. In the event a potential project is not progressed for any reason, including failure to FID, or additional funding provides for greater capacity to complete projects, we may further evaluate and develop one or more of these early-stage project opportunities. We will continue to evaluate and identify potential CCUS project opportunities consistent with our goal of offsetting our annual Scope 1, 2 and 3 emissions from our owned and operated upstream and natural gas midstream businesses by the late 2030s. However, we may not receive 100% of the environmental attributes associated with CCUS projects funded in whole or in part by third parties, and, in such cases, we expect to have the right to purchase such environmental attributes BKV would not otherwise receive. Ultimately, we will be able to apply only such portion of the sequestered emissions to offset our own GHG emissions that corresponds to the percentage of environmental attributes BKV receives or purchases.

Large scale CCUS projects are subject to numerous risks and uncertainties, including securing third-party financing, reaching definitive agreements with third parties and obtaining necessary permits and other regulatory approvals, and we may be unable to execute on some or all of these projects, including the projects for which we have reached FID, on the timeline we anticipate, on terms acceptable to us or at all. There can be no guarantee that we will be able to execute and complete any of these identified CCUS projects and there can be no guarantee that we will be able to achieve our net zero Scope 1, 2 and 3 emissions goals. The projected timeline for commercial operations of our CCUS projects depends in part on our ability to fund the anticipated capital requirements for the potential projects that we have identified through up to 50% third party equity or debt funding together with revenues from our upstream business. If sufficient external funding is not available, then we would expect to continue to develop our CCUS business from cash flows from operations on a less accelerated timeline. If we are not able to complete CCUS projects having a sufficient forecasted volume of carbon capture to offset our Scope 1, 2 and 3 annual emissions on the timeline and upon terms that we believe are obtainable, we may not be able to achieve our goal of net zero Scope 1, 2 and 3 emissions from our owned and operated upstream and natural gas midstream businesses by the late 2030s.

In addition, our path to net zero solely addresses GHG emissions relating to our owned and operated upstream and natural gas midstream businesses and does not address GHG emissions from our other business operations, namely our CCUS and power generation businesses. Our power generation business is operated through the BKV-BPP Power Joint Venture, which owns the Temple Plants. Although we believe our current path to net zero will be sufficient to reduce emissions related to our existing owned and operated upstream and natural gas midstream businesses, the future growth or expansion of such businesses will result in additional GHG emissions. We believe our approach to reducing the emissions from our owned and operated upstream and natural gas midstream operations is repeatable and scalable. Through continued investment and expansion of our “Pad of the Future” program and our emissions and leak surveys, as well as additional CCUS and solar projects, we believe we will be able to offset any such additional emissions from our owned and operated upstream and natural gas midstream businesses resulting from our continued growth.

Business Strategy

Our strategy is to create value for our stockholders by managing and growing our integrated asset base and focusing on our net zero objectives. Our strategy has the following principal elements:

- **Optimize the value of our core businesses.** We utilize technology and data analysis to enhance our assets and operations, which we believe improves operational efficiencies, reduces our emissions and helps us realize our operational and financial goals as we continue to scale our business. For example, our “Pad of the Future” program, which includes conversion of natural gas-powered instrument pneumatics to compressed air or electric power instruments on existing pads, combined with emission and leak surveys, is expected to eliminate or reduce approximately 1.05 Mtpy CO_2e of our annual GHG emissions by the end of 2027. Our “Pad of the Future” application also improves pad efficiencies and operating revenue. We have also improved pad efficiencies and reduced lease operating costs through improvements including leveraging of data analytics to coordinate the workforce, prioritize high-value activity, and assess individual well profitability; automating critical plunger set points; in-sourcing key services such as slick-line, value re-builds, compression overhaul, and location repair and maintenance; as well as entering water share arrangements to reduce disposal and trucking cost. Through these process improvements, we reduced our operating costs for our operated NEPA assets by 33.0% for the trailing twelve months ended June 30, 2024, as compared to the trailing twelve months ended March 31, 2019, which period represented the first year of our operatorship of the NEPA assets. Similarly, we reduced our operating costs for our Barnett assets by 12.8% for the trailing twelve months ended June 30, 2024, as compared to the trailing twelve months ended June 30, 2023, which period represented the first year of our operatorship of the Barnett assets acquired from the Exxon Barnett Acquisition and the Devon Barnett Acquisition combined. Additionally, our refrac and long lateral drill programs have allowed us to organically grow our reserves base. As of December 31, 2023, our Barnett refrac program has added 317 Bcfe of proved reserves since its inception in early 2021. As of December 31, 2023, our Barnett refrac program has an average of $0.57/Mcfe in finding and development costs with respect to proved reserves. This refrac program employs specifically designed perforating technology and a suite of innovative refrac techniques, as well as advanced refrac designs and diversion methods to maximize reserves recovery and economics from legacy Barnett wells. Our Barnett new well drilling program has added 645 Bcfe of proved reserves since our entry into the Barnett. By combining our reserves into a growing asset base with vertically integrated components, we believe we can enhance margins and create a “closed loop” emissions reduction strategy that reduces Scope 1 and 2 emissions from our owned and operated upstream and natural gas midstream businesses and captures margin across the value chain.
- **Grow through opportunistic, synergistic acquisitions.** A significant element of our business strategy is gaining scale through accretive acquisitions. We have a track record of growth through acquisitions, which we believe have been at attractive valuations. Since 2016, we have completed 19 acquisitions, resulting in approximately 69% compound annual growth rate of Adjusted EBITDAX as of June 30, 2024. We believe our business model, management team experience and application of technology enable us to quickly and efficiently integrate additional upstream, midstream, power and CCUS assets into our business.
- **Maintain a disciplined financial strategy.** We believe we can execute on our business plan and grow our business while continuing to generate substantial Adjusted Free Cash Flow. We target a Maintenance Reinvestment Rate of less than 45% and an Upstream Reinvestment Rate of less

than 50%. We are focused on our goal of maintaining a conservative financial profile, with a long-term Total Net Leverage Ratio target of 1.0x to 1.5x. Although we may allow our leverage ratio to exceed our target in connection with a strategic acquisition, we would seek to return our leverage level to between 1.0x and 1.5x as soon as reasonably possible thereafter through Adjusted Free Cash Flow and, if needed, reduced activity levels. To support the generation of future Adjusted Free Cash Flow, we have a policy of hedging approximately 25% to 60% of our forecasted production volumes over a given 12 to 48-month period, subject to maintaining compliance with the hedging requirements in the RBL Credit Agreement. We believe our capital efficient project inventory, low-decline natural gas production and multiple, integrated business lines will provide consistent returns through varying business cycles. We intend to apply our cash flows to manage our indebtedness in line with our leverage target, fund our capital expenditure program, enhance stockholder value and execute opportunistic acquisitions across our four business lines. Adjusted EBITDAX is not a financial measure calculated in accordance with GAAP. See "*Prospectus Summary — Summary Historical Financial Information — Non-GAAP Financial Measures*" for a description of this measure and a reconciliation to the most directly comparable GAAP measure.

- **Focus on our net zero objectives.** We seek to apply our integrated business model, CCUS projects and carbon-negative initiatives to realize Scope 1 and 2 net zero emissions from our owned and operated upstream and natural gas midstream businesses by the early 2030s. We believe we can achieve this through reductions in and offsets to our owned and operated upstream and natural gas midstream emissions from our "Pad of the Future" emissions reductions program and emissions monitoring and leak surveys, the retirement of SRECs generated by the BKV-BPP Power Joint Venture's planned solar facility and executing CCUS projects. We believe that carbon emissions within the United States can be reduced substantially through carbon capture on natural gas production, power plants, processing facilities and other energy and industrial infrastructure. As such, in addition to lowering emissions in our owned and operated upstream and natural gas midstream businesses, CCUS for third parties has become a focus of our business plan. We expect our CCUS projects to represent a meaningful portion of our budgeted capital expenditures going forward as we advance our long-term goal of offsetting Scope 3 emissions from our owned and operated upstream and natural gas midstream businesses.
- **Encourage innovation.** Our distinctive culture encourages innovation with a value-driven focus that feeds into our competitive advantage. For example, our emphasis on the efficient application of modern technology led to the development of our "Pad of the Future" program, our advancements in Barnett refracs and other operational improvements. We intend to continue to develop, retain and add to our already talented, experienced and forward-thinking employees. Our unified team and mantra of "Being a force for good" underpin our core values and provides us with confidence in our ability to successfully manage and grow our business.
- **Deliver robust returns to stockholders.** We intend to prioritize delivering strong returns to our stockholders through our focus on creating stockholder value. We believe our operational expertise in successfully drilling and refracturing wells, acquiring and integrating assets purchased at attractive valuations and maintaining financial discipline will underpin our ability to meet our stockholder return goals. Our integrated businesses and natural gas-weighted, low-decline PDP reserves collectively reduce our downside risk while providing asymmetric upside returns from the confluence of commodity price uplift potential, operational improvement and development opportunities, and future accretive acquisition opportunities. See "*Risk Factors — Risks Related to the Offering and Our Common Stock*."

Competitive Strengths

We have a number of strengths that we believe will help us successfully execute our business strategy, including:

- **Integrated asset base well positioned for sustainable growth.** Our upstream, midstream and power asset bases reside in geographically concentrated areas with numerous asset acquisition opportunities in close proximity. Our proven ability to successfully negotiate, close and integrate these acquisition opportunities quickly and cost effectively will allow us to continue to grow our portfolio of assets synergistically. We believe that scale and the continued application of technological developments and operational excellence, combined with stable, low-decline production profiles, will continue to generate significant capital efficient development opportunities in the Barnett and NEPA.

- **High quality, low decline assets serving key demand markets.** Through a series of accretive acquisitions, we have established an extensive and largely contiguous acreage position in two key markets, the Barnett and NEPA. Our Barnett assets cover approximately 460,000 net acres, with an approximately 80.2% Effective NRI, and are located in close proximity to key Gulf Coast industrial and LNG demand centers. Our NEPA assets consist of approximately 19,480 net acres (after giving effect to the sales of BKV Chaffee and certain assets held by BKV Chelsea) in one of the most prolific parts of the Marcellus Shale and are located within less than 200 miles to key demand markets in the U.S. Northeast. We believe the geologic, operational and engineering risks associated with our leasehold acreage have been significantly mitigated through historical development activity. Our PDP reserves had an estimated 8.1% year-over-year average base decline rate over the next 10 years as of December 31, 2023. Additionally, we have an inventory of over 15 years of refrac and new drill locations within our core acreage that give us the flexibility to maintain or slightly grow current production levels, depending on the commodity cycle.

- **Lower emissions energy production.** We are focused on achieving Scope 1 and 2 net zero emissions from our owned and operated upstream and natural gas midstream businesses by the early 2030s. We believe we have a comprehensive ESG program, which is overseen and directed by an executive ESG steering committee. In February 2023, we re-certified most of our production under the TrustWell environmental assessment program of Project Canary, an environmental certification and ESG data company. We achieved a Gold rating from Project Canary, the second highest rating a company can receive for its production, qualifying the certified portion of our natural gas production as RSG. As part of its environmental assessment, Project Canary analyzes and certifies our production on a well by well basis. As of June 30, 2024, approximately 70% of our NEPA production and approximately 45% of our Barnett production was re-certified. We intend to continue an environmental assessment of substantially all of our existing production. In addition, we intend to advance the market for our produced gas beyond RSG and its current certification towards Carbon Sequestered Gas, a Scope 1, 2 and 3 carbon neutral natural gas product. We expect that production of Carbon Sequestered Gas will be achieved by bundling RSG with carbon credits sufficient to offset the estimated emissions associated with the production, gathering and boosting of such RSG, as well as the estimated emissions from its transmission, distribution (if applicable) and ultimate combustion, with the quantified emissions and the requisite volume of CCUS offsets being third-party certified. We have an agreement with a third party to establish the blockchain ledger and tokens; however, this process is dependent upon the development of the necessary technology by such third party. In addition, we expect to utilize the blockchain ledger and tokens with the American Carbon Registry, once that registry has been established. The carbon credits included in our Carbon Sequestered Gas will be generated by our CCUS projects, as described in "— *Overview — Our Operations — Path to Net Zero Emissions*," and retired against our Scope 1 and/or Scope 3 emissions. We believe Carbon Sequestered Gas could potentially provide a decarbonized, certified and qualified fuel and retired credits bundle that is a differentiated and premium product. Additionally, we have a plan to achieve net zero Scope 1 and 2 emissions from our owned and operated upstream and natural gas midstream businesses by the early 2030s based on our "Pad of the Future" program, emissions monitoring and leak surveys and the retirement of SRECs generated by the BKV-BPP Power Joint Venture's planned solar facility and executing CCUS projects. However, if we are not able to complete CCUS projects having sufficient sequestration volumes of CO_2 on this timeline, we may consider alternatives to offset the Scope 1 and Scope 2 emissions from our owned and operated upstream and natural gas midstream businesses (including the purchase of verified offset credits from the BKV-BPP Power Joint Venture or third parties). Ultimately, we may not be able to achieve this goal, produce Carbon Sequestered Gas or obtain a premium on such gas (particularly to the extent there are any concerns regarding the type, ownership or quality of offsets or other environmental attributes used for our characterization of Carbon Sequestered Gas).

- **Efficient use of capital.** Our deep, high-graded inventory of refrac opportunities coupled with our inventory of new drill locations allow us to create meaningful additional cash flow with comparatively modest additional capital investments. We utilize operational improvements such as operational process and procurement efficiencies, use of existing field infrastructure, innovative and cost-effective refrac techniques and designs (including diversion methods), drilling long laterals in the Barnett, and optimizing available midstream capacity to further maximize our capital efficiency. Through our midstream, power and CCUS business lines, we are capturing margin across the value chain.

- **Well capitalized and conservative balance sheet.** Following the completion of this offering, we intend to continue to maintain a strong balance sheet and fund our upstream, midstream and power operations predominantly with internally generated cash flows. We believe that the low decline, predictable nature of our upstream production profile, combined with our hedging plan and reinvestment rate targets, will allow us to successfully meet our leverage goals.
- **High caliber and proven management team.** We maintain a highly experienced and knowledgeable management team with an average of over 25 years of experience among our senior management team. Our leadership team has significant experience managing integrated energy and power assets for large-scale enterprises, including companies such as PTT Exploration and Production Public Company Limited ("PTT Exploration") and BP p.l.c. ("BP"). Furthermore, our sponsor, Banpu, one of Asia Pacific's largest integrated energy companies, provides us with unique and valuable insights into optimizing our integrated energy business.

Our History

In June 2015, our Chief Executive Officer, Chris Kalnin, and Banpu founded our predecessor, BKV O&G, a Delaware partnership developed for oil and gas investments owned primarily by Banpu and managed by Kalnin Ventures, with the goal of creating long-term sustainable value in the energy industry.

In 2016, BKV O&G acquired from Range Resources a 29.4% interest in certain midstream assets and an approximately 24% interest in certain upstream assets in the Marcellus Chaffee Corners area that are operated by Repsol. From 2017 to 2019, BKV completed a series of other accretive acquisitions, including two major acquisitions of upstream and midstream assets in NEPA from Carrizo Oil and Gas and its non-operated partner, Reliance Industries, and BKV O&G devoted its time to strengthening its technological, exploration, production and operational capabilities.

On May 1, 2020, we completed a corporate restructuring in which we converted all of the interests and assets owned by BKV O&G (the "BKV O&G Conversion") and also acquired Kalnin Ventures (the "KV Acquisition"). The BKV O&G Conversion and the KV Acquisition resulted in our formation as a new consolidated corporate entity, BKV Corporation. See "— *The Corporatization Event*" for more information about our corporate restructuring.

In October 2020, we became one of the largest natural gas producers by volume in the Barnett, following our acquisition of more than 289,000 net acres, 3,850 producing operated wells and related upstream assets in the Barnett from Devon Energy (the "Devon Barnett Acquisition") for a cash purchase price of $570.0 million.

In July 2021, we launched our natural gas-based power generation business with the formation of BKV-BPP Power, a joint venture owned 50% by us and 50% by BPPUS, a wholly owned subsidiary of Banpu Power and an affiliate of our sponsor, Banpu. In November 2021, BKV-BPP Power acquired Temple Generation Intermediate Holdings II, LLC, the owner of 100% of the interests in Temple I, a combined cycle gas turbine and steam turbine power plant located in the ERCOT North Zone in Temple, Texas.

In September 2021, we purchased a non-operated interest spanning over 3,000 net acres from Black Falcon Energy, LLC, a managing company for Jamestown Resources, LLC, Larchmont Resources, LLC and Pelican Energy, LLC in the Barnett and NEPA.

In March 2022, we launched our CCUS business line, BKV dCarbon Ventures, and we reached FID and entered into a definitive agreement in June 2022 in connection with our first CCUS project, the Barnett Zero Project, with EnLink to dispose of, and geologically sequester, CO_2 generated as a byproduct of the production of our EnLink-gathered natural gas in the Barnett. We commenced commercial operations with the initial injection of CO_2 waste at the Barnett Zero Project in November 2023, and intend to use this project as a prototype for modular NGP projects that can be repeated and quickly scaled.

In June 2022, we closed the acquisition (the "Exxon Barnett Acquisition") of natural gas upstream and associated midstream infrastructure in the Barnett from XTO Energy, Inc. and Barnett Gathering LLC, subsidiaries of Exxon Mobil Corporation, for a total purchase price of $750.0 million, plus additional contingent consideration of up to $50.0 million depending on future natural gas prices. Pursuant to the Exxon Barnett Acquisition, we acquired approximately 165,000 total net acres in the State of Texas that are approximately 99% held by production and located primarily in Tarrant, Johnson and Parker counties, with additional smaller positions in Jack, Wise, Denton, Erath, Hood and Ellis counties (our "2022 Barnett Assets"). These upstream assets include low decline wells, ideal for delivering consistent cash flow, and high average working interests of approximately 94% in over 2,100 operated wells. The Exxon Barnett Acquisition also included the addition of 129 employees and approximately 778 miles of gathering pipelines, compression and processing midstream infrastructure.

Pursuant to a development agreement with Verde CO2, an independent carbon capture and sequestration developer and operator, certain CCUS projects throughout the United States were identified and evaluated. We terminated the development agreement in November 2023 and, in accordance with the agreement's terms, Verde CO2 assigned to BKVerde the pore space leaseholds and other assets associated with two potential near-term industrial CCUS projects under evaluation by BKV as of such date. Verde CO2 has the option to purchase up to a 5% minority economic interest in two of these potential industrial projects and, to the extent it exercises such option, would be entitled to a pro rata share of the Section 45Q tax credits associated with the CCUS projects in which it invests. Since August 2022, we paid $26.0 million to Verde CO2 under the development agreement. We believe such investment will expand our CCUS and GHG emissions reduction efforts as we seek to decarbonize industrial point sources of various sizes through carbon capture and permanent sequestration. We expect to fund BKVerde through our cash flows from operations but may also obtain funding from external sources.

In October 2022, BKV dCarbon Ventures reached internal FID to develop our second CCUS project to dispose of, and geologically sequester, CO_2 generated as a byproduct of the production of our natural gas in the Barnett and will utilize our BKV Midstream assets to do so.

In November 2022, we entered into a non-binding letter of intent with ENGIE to build a framework for verifiable environmental attributes with the use of carbon credits applied to natural gas energy. We expect that production of Carbon Sequestered Gas will be achieved by bundling RSG with carbon credits sufficient to offset the estimated emissions associated with the production, gathering and boosting of such RSG, as well as the estimated emissions from its transmission, distribution (if applicable) and ultimate combustion, with the quantified emissions and the requisite volume of CCUS offsets being third-party certified. The carbon credits included in our Carbon Sequestered Gas will be generated by our CCUS projects, as described in "*— Overview — Our Operations — Path to Net Zero Emissions*," and retired against our Scope 1 and/or Scope 3 emissions.

In January 2023, we purchased additional interest in acquired wells as part of the Exxon Barnett Acquisition for $5.4 million and identified 13 potential locations for drilling on existing pads and leases.

In July 2023, BKV-BPP Power acquired CXA Temple 2, LLC, the owner of 100% of the interests in Temple II, a combined cycle gas turbine and steam turbine power plant located on the same site as Temple I in the ERCOT North Zone in Temple, Texas.

The Corporatization Event

Prior to May 1, 2020, BKV O&G held 100% of the outstanding equity interests in BKV Chaffee, BKV Chelsea, BKV Operating and BKV Barnett (the "BKV O&G Group"). During this period, Banpu held approximately 97% of BKV O&G's limited partner interests, and Kalnin Capital Partners, L.P. (the "General Partner") held BKV O&G's general partner interest.

On May 1, 2020, Banpu and the General Partner incorporated BKV Corporation and restructured BKV O&G through a contribution by Banpu, the other limited partners and the General Partner of all of the partnership interests in BKV O&G to BKV Corporation in exchange for common stock of BKV

Corporation. In addition, Kalnin Ventures, which previously managed BKV O&G, was contributed to BKV Corporation in exchange for BKV Corporation common stock. As a result of these transactions, as of May 1, 2020, the BKV O&G Group and Kalnin Ventures became wholly owned subsidiaries of BKV Corporation. We refer to this series of transactions collectively as the "Corporatization Event."

Our Relationship with Banpu

BNAC, our majority stockholder, is an indirect, wholly owned subsidiary of Banpu, our ultimate parent company. Immediately prior to this offering, Banpu owned approximately 96.3% of our common stock and will own approximately   % at the completion of this offering (or approximately   % if the underwriters exercise in full their option to purchase additional shares of our common stock). Banpu has informed us that although it may reduce a portion of its ownership position over time, it intends to remain a long-term stockholder and supporter of BKV. If, after this initial public offering, any person or group (other than Banpu and its controlled affiliates, excluding portfolio companies and operating companies) acquires 35% or more of our equity interests, or if any person or group acquires a greater percentage of our equity interests than are then held by Banpu and its controlled affiliates (excluding portfolio companies and operating companies of Banpu), such event will be an event of default under the RBL Credit Agreement. See "*Risk Factors — Risks Related to Our Relationship with Banpu and its Affiliates.*"

Banpu is a multi-billion U.S. dollar market cap energy company publicly traded in Thailand. With nearly four decades of experience in business operations covering 10 countries across the Pacific Rim region and the United States, Banpu is an international versatile energy provider committed to its Greener & Smarter strategy, which prioritizes environmentally sustainable businesses and leverages smart technologies and innovations.

Banpu also owns approximately 78.66% of Banpu Power. Banpu Power is a public company listed on the Stock Exchange of Thailand. Banpu Power is the owner of BPPUS, our partner in the BKV-BPP Power and BKV-BPP Cotton Cove joint ventures.

For additional information regarding our relationship with Banpu, see "*Certain Relationships and Related Party Transactions*" and "*Management — Conflicts of Interest.*"

Our Operations

Natural Gas Production

Our Geographic Focus

We are engaged in the acquisition, operation and development of natural gas and NGL properties located primarily in the Barnett (approximately 460,000 net acres) and NEPA (approximately 19,480 net acres) with a combined total Company net production of approximately 807.6 MMcfe/d for the six months ended June 30, 2024. In addition, we own an aggregate of approximately 4,500 net mineral fee acres located in the Barnett and NEPA. The Barnett has a diversified production stream of natural gas and NGLs located approximately 300 miles from major Gulf Coast industrial centers and LNG export markets. NEPA is composed predominantly of organically rich shale and is generally acknowledged as one of North America's largest and richest sources of natural gas.

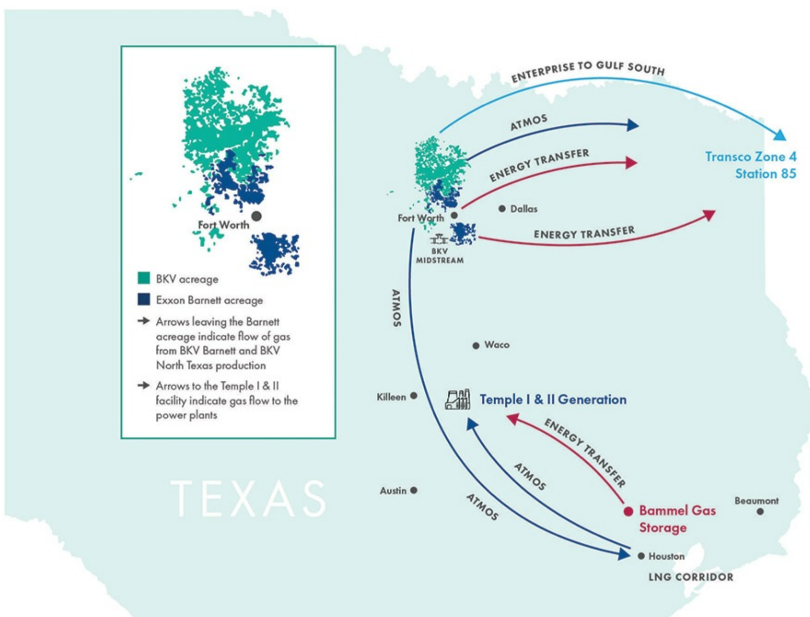
Our upstream assets are predominantly located in the Barnett, which is where horizontal drilling was pioneered and which has the advantage of more than 15 years of technological advancements, proximity to demand hubs and a significant amount of midstream and other infrastructure in place. As of December 31, 2023, we also enjoyed an average 7.7% 10-year Barnett base production decline on a current production base of approximately 718.2 MMcfe/d. Using modern technologies, we can drill and complete more profitably and successfully with longer laterals, optimal 750 foot down hole well spacing and latest shale fracturing designs.

More than a decade of technological advancements since the discovery of the Barnett, combined with significant remaining gas and NGL resources in place, have created a highly capital efficient opportunity to re-stimulate legacy wellbores to meaningfully increase production and enhance recovery factors and reserves.

We also have negotiated a midstream contract, covering 44% of our Barnett acreage, that offers incentive gathering and processing rates for new drills and restimulations, enhancing our margins and project economics alike. We entered the Barnett in October of 2020, through our completion of the Devon Barnett Acquisition. As of December 31, 2023, we had 78 proved undeveloped horizontal locations and 501 proved developed non-producing refrac candidates in the Barnett. For a discussion of how we identify drilling locations and refrac candidates, please see " — *Determination of Identified Drilling and Refracture Locations*."

We are the largest natural gas producer by gross operated volume in the Barnett. During the six months ended June 30, 2024, our Barnett properties, including both operated and non-operated wells, produced 124.2 Bcfe (or an average of 682.5 MMcfe/d). During the years ended December 31, 2023, 2022, and 2021, our Barnett properties, including both operated and non-operated wells, produced 262.1 Bcfe (or an average of 718.2 MMcfe/d), 228.7 Bcfe (or an average of 626.3 MMcfe/d), and 190.1 Bcfe (or an average of 520.9 MMcfe/d), respectively. We did not drill any of our own operated wells in our Barnett properties during 2021 and drilled 115 wells in 2022. Additionally, in November 2020, we began a restimulation program to develop economic incremental reserves in existing wellbores and arrest the overall field production decline. In connection with such program, we completed 122 horizontal and 26 vertical restimulations in 2021, 128 horizontal and 35 vertical restimulations in 2022, and ten horizontal and 22 vertical restimulations in 2023. We led the industry in number of executed horizontal restimulations in 2021 and 2022, according to public completion reports. During the six months ended June 30, 2024, we did not complete any restimulations.

The image below reflects our Barnett acreage that was acquired in the 2020 Barnett Acquisition (Green) and the Exxon Barnett Acquisition (Blue), with the arrows indicating the direction of flow to existing markets and identifying the respective third parties with which BKV has secured downstream capacities. The image reflects how we are now positioned in the core of the Barnett with transportation to key gulf coast markets. Transportation to the East and the South provide key flexibility and optionality for gas transportation out of the basin. This strategically positions us geographically to utilize existing infrastructure to the gulf without needing to rely on new-build pipelines such as in the Permian and Haynesville.



In NEPA, we have built our position through twelve accretive acquisitions since May 2016. We have an attractive production base comprising approximately 19,480 net acres located primarily in Wyoming, Susquehanna and Bradford counties, Pennsylvania, in one of the most prolific areas of the play. With respect to our operated and non-operated assets in NEPA, as of December 31, 2023, our position consisted of an average 89.4% working interest and 72.6% NRI on operated wells that yield 100% lean natural gas. We enjoy a significant non-operated position in NEPA. In addition, as of December 2023, we had approximately 21 new well locations for near-term development in NEPA, five of which were sold in connection with the sales of BKV Chaffee and certain assets held by BKV Chelsea.

During six months ended June 30, 2024 and the years ended December 31, 2023, 2022 and 2021, we produced 22.8 Bcf (or an average of 125.2 MMcf/d), 51.7 Bcf (or an average of 141.5 MMcf/d), 50.8 Bcf (or an average of 139.2 MMcf/d) and 56.1 Bcf (or an average of 153.7 MMcf/d), respectively, from our NEPA properties, including both operated and non-operated wells. We did not drill any new wells in NEPA in 2021. During the year ended December 31, 2022, we drilled five wells in NEPA. However, we utilized a combination of compression projects and drilled but uncompleted (DUC) well completions to slow production declines and optimize production.

On June 14, 2024, we sold our wholly owned subsidiary, BKV Chaffee, which owned a non-operated interest in approximately 9,800 net acres and 116 gross (24.2 net) wells and 122 Bcfe of proved reserves in NEPA, as well as our interest in the Repsol Oil & Gas operated midstream system, for a purchase price of $106.7 million, subject to adjustment. On June 28, 2024, our wholly owned subsidiary, BKV Chelsea, sold certain of its non-operated upstream assets, including its interest in approximately 6,800 net acres and 214 gross (15.4 net) wells and 35 Bcfe of proved reserves in NEPA for a purchase price of $25.0 million, subject to adjustment.

The image below reflects our NEPA acreage (Green), which, after giving effect to the sales of BKV Chaffee and certain assets held by BKV Chelsea, spans the northeast portion of Pennsylvania and is comprised predominantly of operated assets, with the arrows indicating the direction of flow to existing markets and identifying the respective third parties with which BKV has secured downstream capacities. Our downstream transportation has the flexibility to move West and South into gulf coast markets via the Tennessee Gas Pipeline as well as into the northeast corridor via the Millennium pipeline while also maintaining intra-basin optionality.

Our Technology-Enabled Business

Our integrated business model allows us to develop, test and deploy new technologies to drive efficiencies across the business and to reduce our own emissions. We leverage technology in two important ways: we utilize our Data Lake and in-house data science team to drive efficiencies and insights across the business and we utilize probabilistic modeling approaches and advance risk management techniques to enhance our decision-making abilities, particularly with regards to potential acquisitions. We employ a technology-focused approach, such as utilization of our proprietary instrument air packages, satellite and perimeter pad emissions monitoring, and advanced production and emissions measurement, to enable methane measurement and mitigation, and emission elimination strategies, that reduce CO_2e emissions across our operations.

Our operations in the Barnett and NEPA have been increasingly automated through a program called “Autotune,” which is an effort to optimize and automate plunger lift systems to increase production through autonomous dynamic tuning of plunger control inputs. This Autotune method utilizes computer algorithms which toggle and optimize various input and control variables for plunger lift systems to increase production time for an average well, as compared to a baseline (based on a manual method of managing plunger input and control variables).

We have implemented our “Pad of the Future” program in our upstream business, with the objectives of converting natural gas-powered instrument pneumatics to compressed air-powered functionality on existing pads, significantly reducing our GHG emissions and improving pad efficiencies and economics. In addition, we have implemented emissions surveys, an advanced four-tiered emissions monitoring and mitigation strategy utilizing specialized surveillance technology. The BKV-BPP Power Joint Venture has obtained permits for and constructed 2.5 MW of commercial solar power, with plans to install up to 5 MW of commercial solar power within the next three years. We may purchase the SRECs generated by the BKV-BPP Power Joint Venture’s planned solar facility and then retire such SRECs to neutralize at least a portion of our Scope 2 emissions from our electricity usage in our owned and operated upstream and natural gas midstream businesses.

Our “Pad of the Future” program primarily seeks to review our pad-level operations and mitigate or eliminate GHG emissions from those operations. The program targets equipment, such as natural gas operated pneumatic controllers, that is considered to be a significant source of methane emissions and thereby overall GHG emissions from our upstream assets. As part of the program, we have successfully completed the conversion of the BKV-owned pneumatic controllers at our NEPA upstream operations from operating on natural gas to compressed air. Additionally, we have successfully replaced the use of natural gas combusted at the GPU burners located at our NEPA upstream assets with electrically-operated heat trace that will reduce our overall GHG emissions associated with natural gas combustion. We note that our implementation of the “Pad of the Future” program is primarily targeted towards the reduction of methane emissions, as methane is a potent GHG that represents a significant proportion of the Scope 1 GHG emissions from our owned and operated upstream businesses. Implementation of our “Pad of the Future” program in calendar years 2021 through 2023 has resulted in a reduction of the Scope 1 emissions from our owned and operated upstream businesses of approximately 0.52 Mtpy CO_2e. For additional information about our “Pad of the Future” program, see “— *Our Operations — Planned Path to Net Zero Emissions*.”

In February 2023, we re-certified most of our production under the TrustWell environmental assessment program of Project Canary, an environmental certification and ESG data company. We achieved a Gold rating from Project Canary, the second highest rating a company can receive for its production, qualifying the certified portion of our natural gas production as RSG. As part of its environmental assessment, Project Canary analyzes and certifies our production on a well by well basis. As of June 30, 2024, approximately 70% of our NEPA production and approximately 45% of our Barnett production was re-certified. We intend to continue an environmental assessment of substantially all of our existing production. In addition, we intend to advance the market for our produced gas beyond RSG and its current certification towards Carbon Sequestered Gas, a Scope 1, 2 and 3 carbon neutral natural gas product. We expect that production of Carbon Sequestered Gas will be achieved by bundling RSG with carbon credits sufficient to offset the estimated emissions associated with the production, gathering and boosting of such RSG, as well as the estimated emissions from its transmission, distribution (if applicable) and ultimate combustion, with the quantified emissions and the requisite volume of CCUS offsets being third-party certified. We have an agreement with a third party to establish the blockchain ledger and tokens; however, this process is dependent upon the development of the necessary technology by such third party. In addition, we expect to utilize the blockchain ledger and tokens with the American Carbon Registry, once that registry has been established. The carbon credits included in our Carbon Sequestered Gas will be generated by our CCUS projects, as described below in "— *Our Operations — Planned Path to Net Zero Emissions*" and retired against our Scope 1 and/or Scope 3 emissions. We believe Carbon Sequestered Gas could potentially provide a decarbonized, certified and qualified fuel and retired credits bundle that is a differentiated and premium product. Through production of RSG and Carbon Sequestered Gas, we believe we can provide reliable and affordable energy, while actively participating in the energy transition.

Our Reserves

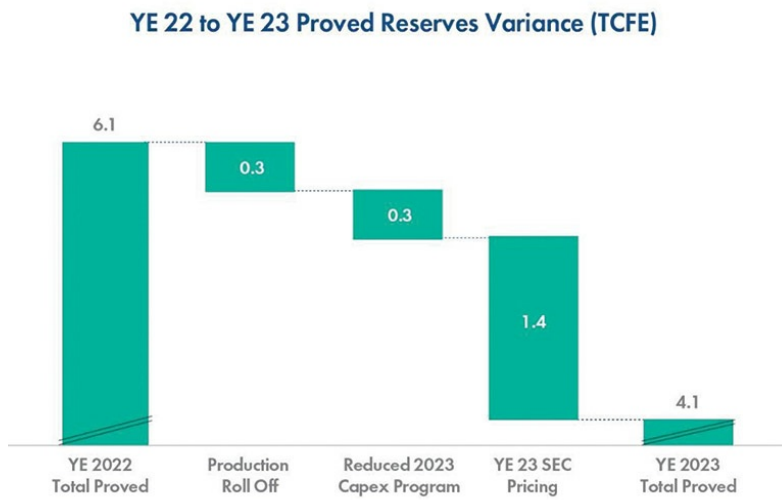
The following table summarizes our natural gas and oil properties as of December 31, 2023 and our average net daily production for the year ended December 31, 2023:

	December 31, 2023							
	Estimated Total Proved Reserves							
Operating Region	**Natural Gas (MMcf)**	**Natural Gas Liquids (MBbls)**	**Oil (MBbls)**	**Total (MMcfe)**	**Average Net Daily Production (MMcfe/d)**	**Average Reserves Life (years)**	**Producing Wells**	**Net Acres**
Barnett	2,557,868	184,165	1,051	3,669,164	718.2	15.3	6,786	459,912
NEPA	424,627	—	—	424,627	141.5	21.7	427	36,865
Total	2,982,495	184,165	1,051	4,093,791	859.7	16.2	7,213	496,777

The following table summarizes our natural gas and oil properties as of December 31, 2022 and our average net daily production for the year ended December 31, 2022, including the properties we acquired in the Exxon Barnett Acquisition:

	December 31, 2022							
	Estimated Total Proved Reserves							
Operating Region	**Natural Gas (MMcf)**	**Natural Gas Liquids (MBbls)**	**Oil (MBbls)**	**Total (MMcfe)**	**Average Net Daily Production (MMcfe/d)(1)**	**Average Reserves Life (years)**	**Producing Wells**	**Net Acres**
Barnett	3,955,330	211,500	1,868	5,235,544	732.7	19.6	6,825	457,787
NEPA	900,346	—	—	900,346	139.2	17.7	397	36,886
Total	4,855,676	211,500	1,868	6,135,890	871.9	19.3	7,222	494,673

(1) The production rate for the properties acquired in the Exxon Barnett Acquisition was based on management's review of the historical accounting information with respect to such assets.



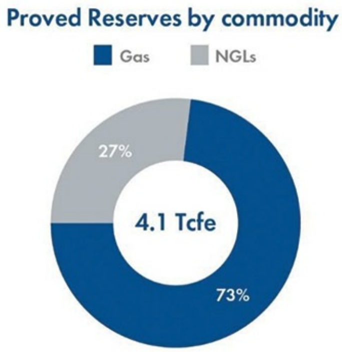
Based on forecasts used in our reserves reports, our PDP reserves as of December 31, 2023 had estimated average five-year and ten-year annual decline rates of approximately 9.1% and 8.1%, respectively. Our Company-wide 2023 base decline rate for all categories of reserves was 11.1%. As a result of this overall low decline profile of our natural gas and oil assets, coupled with refrac opportunities that are capital efficient projects, we are able to maintain flat production year over year with a relatively low reinvestment rate. We believe the combination of our high margin profile and our conservative reinvestment rate approach, supported by our low decline reserves, will allow us to generate significant Adjusted Free Cash Flow to (i) deliver stockholder returns and (ii) opportunistically fund value accretive growth opportunities.

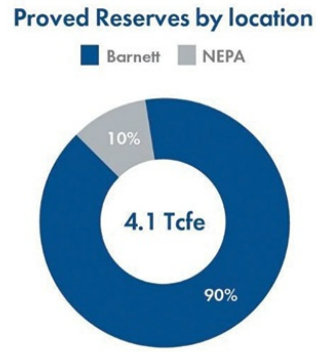
The following table illustrates the weighted average decline profiles and total production in the year ended December 31, 2023 associated with our proved reserves as of December 31, 2023:

	December 31, 2023					
					Weighted Average Annual PDP Decline(1)	
Operating Region	Estimated Total Proved Reserves (MMcfe)	% Natural Gas	% Natural Gas Liquids	% Oil	Five Year	Ten Year
Barnett	3,669,164	69.7%	30.1%	0.2%	8.5%	7.7%
NEPA	424,627	100%	—	—	12.2%	10.1%
Total	4,093,791	72.8%	27%	0.2%	9.1%	8.1%

(1) Reflects the estimated average year over year decline rates of our base reserves as of December 31, 2023 for the five-year period ending December 31, 2028 and the ten-year period ending December 31, 2033, in each case based on the forecasts used in estimating our proved reserves.

The following charts summarize our proved reserves by commodity and proved reserves by location as of December 31, 2023:





The following table illustrates the weighted average decline profiles and total production in the year ended December 31, 2022 associated with our proved reserves as of December 31, 2022:

	December 31, 2022					
					Weighted Average Annual PDP Decline(1)	
Operating Region	Estimated Total Proved Reserves (MMcfe)	% Natural Gas	% Natural Gas Liquids	% Oil	Five Year	Ten Year
Barnett	5,235,544	75.6%	24.2%	0.2%	7.8%	6.7%
NEPA	900,346	100%	—	—	13.5%	10.3%
Total	6,135,890	79.2%	20.6%	0.2%	8.7%	7.3%

(1) Reflects the estimated average year over year decline rates of our base reserves as of December 31, 2022 for the five-year period ending December 31, 2027 and the ten-year period ending December 31, 2032, in each case based on the forecasts used in estimating our proved reserves.

The following table illustrates the weighted average decline profiles and total production in the year ended December 31, 2021 associated with our proved reserves as of December 31, 2021:

	December 31, 2021					
					Weighted Average Annual PDP Decline(1)	
Operating Region	Estimated Total Proved Reserves (MMcfe)	% Natural Gas	% Natural Gas Liquids	% Oil	Five Year	Ten Year
Barnett	3,496,235	71.5%	28.3%	0.2%	7.0%	6.3%
NEPA	945,528	100%	—	—	12.4%	9.9%
Total	4,441,763	77.6%	22.3%	0.1%	8.3%	7.2%

(1) Reflects the estimated average year over year decline rates of our base reserves as of December 31, 2021 for the five-year period ending January 31, 2026 and the ten-year period ending January 31, 2031, in each case based on the forecasts used in estimating our proved reserves.

Our Acreage

The following table summarizes our acreage position as of June 30, 2024:

	Developed		Undeveloped		Total	
Operating Region	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Barnett[1]	637,983	421,479	40,935	38,293	678,918	459,772
NEPA	22,173	19,011	1,113	469	23,286	19,480
Total	660,156	440,490	42,048	38,762	702,204	479,252

The following table summarizes our acreage position as of December 31, 2023:

	Developed		Undeveloped		Total	
Operating Region	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Barnett[1]	638,193	421,491	41,113	38,421	679,306	459,912
NEPA	63,739	29,501	18,774	7,364	82,513	36,865
Total	701,932	450,992	59,887	45,785	761,819	496,777

The following table summarizes our acreage position as of December 31, 2022:

	Developed		Undeveloped		Total	
Operating Region	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Barnett[1]	638,099	418,919	41,625	38,868	679,724	457,787
NEPA	62,191	28,162	20,823	8,723	83,014	36,885
Total	700,290	447,081	62,448	47,591	762,738	494,672

The following table summarizes our acreage position as of December 31, 2021:

	Developed		Undeveloped		Total	
Operating Region	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Barnett[1]	453,584	261,810	32,120	30,771	485,704	292,581
NEPA	61,971	28,162	20,890	8,816	82,861	36,978
Total	515,555	289,972	53,010	39,587	568,565	329,559

(1) Includes acreage acquired during 2021 from Jamestown Resources, L.L.C., Larchmont Resources, L.L.C., and Pelican Energy, L.L.C., for which acreage the leasehold interest is derived from unit-based assignments and includes 133,470.22 gross and 3,317.69 net developed acres, and no undeveloped acreage.

The percentage of our net undeveloped acreage that is subject to lease expiration over the next three years, if such leases are not renewed, is 0.00% in 2024 and approximately, 0.95% in 2025 and 0.25% in 2026.

Our Productive Wells

The following table sets forth our gross and net productive natural gas and oil wells as of December 31, 2023:

	Producing Natural Gas Wells		Producing Oil Wells		Total		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Operated Wells:							
Barnett	5,614	5,437	6	6	5,620	5,443	96.9%
NEPA	142	127	—	—	142	127	89.4%
Total	5,756	5,564	6	6	5,762	5,570	96.7%
Non-operated Wells:							
Barnett	993	95	1	—	994	95	9.6%
NEPA	272	37	—	—	272	37	13.6%
Total	1,265	132	1	—	1,266	132	10.4%
Total Wells:							
Barnett	6,607	5,532	7	6	6,614	5,538	83.7%
NEPA	414	164	—	—	414	164	39.6%
Total	7,021	5,696	7	6	7,028	5,702	81.1%

The following table sets forth our gross and net productive natural gas and oil wells as of December 31, 2022:

	Producing Natural Gas Wells		Producing Oil Wells		Total		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Operated Wells:							
Barnett	5,822	5,597	9	9	5,831	5,606	96.1%
NEPA	142	126	—	—	142	126	88.7%
Total	5,964	5,723	9	9	5,973	5,732	96.0%
Non-operated Wells:							
Barnett	1,122	95	22	—	1,144	95	8.3%
NEPA	266	36	—	—	266	36	13.5%
Total	1,388	131	22	—	1,410	131	9.3%
Total Wells:							
Barnett	6,944	5,692	31	9	6,975	5,701	81.7%
NEPA	408	162	—	—	408	162	39.7%
Total	7,352	5,854	31	9	7,383	5,863	79.4%

The following table sets forth our gross and net productive natural gas and oil wells as of December 31, 2021:

	Producing Natural Gas Wells		Producing Oil Wells		Total		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Operated Wells:							
Barnett	3,950	3,170	8	6	3,958	3,176	80.2%
NEPA	138	101	—	—	138	101	73.2%
Total	4,088	3,271	8	6	4,096	3,277	
Non-operated Wells:							
Barnett	838	672	8	6	846	678	80.1%
NEPA	256	189	—	—	256	189	73.8%
Total	1,094	861	8	6	1,102	867	
Total Wells:							
Barnett	4,788	3,842	16	12	4,804	3,854	80.2%
NEPA	394	290	—	—	394	290	73.6%
Total	5,182	4,132	16	12	5,198	4,144	

Drilling, Refrac and Restimulation Activity

During the years ended December 31, 2021 and 2020, we did not have an active drilling rig running in any of our operated properties, and therefore we did not drill any wells on these properties. During this period, we completed a total of six wells that were previously drilled but uncompleted wells in NEPA.

During the year ended December 31, 2022, we drilled five wells in NEPA and eleven wells in the Barnett, each of which constitutes a gross operated well and net operated development well. During the year ended December 31, 2022, eleven wells were completed in the Barnett and six wells were completed in NEPA, all of which were net productive. As of December 31, 2022, we had one well (one net) in the process of being drilled in the Barnett and no wells in the process of being drilled in NEPA.

During the year ended December 31, 2023, we drilled three wells in NEPA and eleven wells in the Barnett, each of which constitutes a gross operated well and net operated development well. During the year ended December 31, 2023, seven wells were completed in the Barnett (all of which were net productive) and no wells were completed in NEPA. No wells were drilled during the six months ended June 30, 2024. As of June 30, 2024, we had eight wells (eight net) drilled and uncompleted in the Barnett and three wells (three net) drilled and uncompleted in NEPA. We continue to reduce our average drilling and completion cost per lateral foot in our wells. For example, in 2022, our average drilling and completion cost in the Barnett was $788 per lateral foot, while the same cost during the six months ended June 30, 2024 and during the year ended December 31, 2023, was $658 per lateral foot.

In November 2020, we began a restimulation program in the Barnett to develop economic incremental reserves in existing wellbores and arrest the overall field production decline. In connection with such program, in 2021 and 2022, we led the industry in number of executed horizontal restimulations by completing 143 and 163, respectively, according to public completion reports, and in the year ended December 31, 2023, we completed 32 horizontal and vertical restimulations. Additionally, as of December 31, 2023, we had 78 proved undeveloped horizontal locations and 501 proved developed non-producing refrac candidates in the Barnett. For a discussion of how we identify drilling locations and refrac candidates, please see "*— Determination of Identified Drilling and Refracture Locations*." During the six months ended June 30, 2024, we did not complete any restimulations.

Sales Volumes and Unit Prices

The following table summarizes sales volumes, sales prices and production cost information for our net natural gas and production for the six months ended June 30, 2024 and 2023, and for the years ended December 31, 2023, 2022 and 2021.

	Six Months Ended June 30,		Year Ended December 31,		
	2024	**2023**	**2023**	**2022**	**2021**
Sales Volumes					
Barnett:					
Natural gas (MMcf)	93,976.3	99,829.6	198,099.4	166,771.0	129,960.0
Natural gas liquids (MBbl)	4,986.7	5,280.0	10,553.6	10,187.0	9,829.3
Oil (MBbl)	52.1	63.1	118.6	140.0	123.0
Total Barnett (Bcfe)	124.2	131.9	262.1	228.7	189.7
NEPA:					
Natural gas (MMcf)	22,780.1	27,068.6	51,666.9	50,814.0	56,095.1
Natural gas liquids (MBbl)	—	—	—	—	—
Oil (MBbl)	—	—	—	—	—
Total NEPA (Bcfe)	22.8	27.1	51.7	50.8	56.1
Total Company (Bcfe)	147.0	159.0	313.8	279.5	245.8
Average Sales Prices (excluding the impact of derivative settlements)					
Barnett:					
Natural gas (per Mcf)	$ 1.72	$ 2.19	$ 2.28	$ 6.38	$ 3.58
Natural gas liquids (per Bbl)	$ 16.97	$ 17.33	$ 17.80	$ 30.58	$ 22.90
Oil (per Bbl)	$ 71.67	$ 69.70	$ 71.21	$ 84.76	$ 61.46
NEPA:					
Natural gas (per Mcf)	$ 0.79	$ 1.42	$ 1.12	$ 4.85	$ 2.34
Natural gas liquids (per Bbl)	$ —	$ —	—	$ —	$ —
Oil (per Bbl)	$ —	$ —	—	$ —	$ —
Total Company (per Mcfe)	$ 1.82	$ 2.22	$ 2.25	$ 5.84	$ 3.38
Average Sales Prices (including the impact of derivative prices)(1)					
Natural gas (per Mcf)	$ 1.99	$ 2.29	$ 2.23	$ 3.72	$ 2.29
Natural gas liquids (per Bbl)	$ 17.21	$ 16.98	$ 17.55	$ 27.78	$ 16.03
Oil (per Bbl)	$ 71.81	$ 69.71	$ 70.97	$ 84.76	$ 61.46
Total Company (per Mcfe)	$ 2.19	$ 2.42	$ 2.39	$ 3.95	$ 2.41
Average Production Cost (per Mcfe)(2)					
Barnett	$ 1.43	$ 1.48	$ 1.48	$ 1.43	$ 1.31
NEPA	$ 0.15	$ 0.24	$ 0.24	$ 0.26	$ 0.23
Total Company	$ 1.24	$ 1.27	$ 1.27	$ 1.22	$ 1.06

(1) Impact of derivative prices excludes $13.3 million, $39.1 million, and $46.7 million of gains on derivative contract terminations for the six months ended June 30, 2024 and 2023, and for the year ended December 31, 2023, respectively, and $158.4 million and $30.9 million of derivative contract terminations for the years ended December 31, 2022, and 2021, respectively.

(2) Excludes natural gas and oil ad valorem and production taxes.

Determination of Identified Drilling and Refracture Locations

Proved Drilling and Refracture Locations

As of December 31, 2023, we had approximately 99 gross (91 net) proved undeveloped horizontal drilling locations and 501 gross (476 net) proved developed non-producing refrac candidates. We use production data and experience gains from our development programs to identify and prioritize development of our proved inventory of undeveloped horizontal drilling locations and proved developed non-producing refrac candidates. These drilling locations and refrac candidates are included in our proved inventory only after they have been evaluated technically and are part of a development plan that has been adopted by management indicating that such locations are scheduled to be drilled within five years. As a result of technical evaluation of geologic and engineering data, it can be estimated with reasonable certainty that reserves from these locations are commercially recoverable in accordance with SEC guidelines. Management considers the availability of local infrastructure, drilling support assets, state and local regulations and other factors it deems relevant in determining such locations.

Unproved Drilling and Refracture Locations

We have also identified a multi-year inventory of 436 gross (413 net) unproved horizontal drilling locations and 1,596 gross (1,516 net) unproved refrac candidates. Our unproved horizontal drilling locations and refrac candidates are specifically identified on a field-by-field basis considering the applicable geologic, engineering and production data. We analyze past field development practices and identify analogous drilling opportunities taking into consideration historical production performance, estimated drilling and completion costs, spacing and other performance factors. These horizontal drilling locations and refrac candidates primarily include infill drilling locations, (ii) additional locations due to field extensions and (iii) restimulations. We believe the assumptions and data used to estimate these horizontal drilling locations and refrac candidates are consistent with established industry practices based on the type of recovery processes we are using.

We plan to analyze our acreage for exploration drilling opportunities at appropriate levels. We expect to use internally generated information and proprietary models consisting of data from analog plays, 3-D seismic data, open hole and mud log data, cores and reservoir engineering data to help define the extent of the targeted intervals and the potential ability of such intervals to produce commercial quantities of hydrocarbons.

Base Production Optimization

We seek to be a leader in safe, efficient and accretive base production management. We are highly focused on flattening decline while minimizing costs all while reducing our environmental footprint. Automation and optimization play a pivotal role in this focused approach. Our plunger automation program, *i.e.*, “Autotune,” improves the efficiency of our plunger lift systems, resulting in up to 2% improvement in production. Initiatives like automated equipment actuation and automated water call outs serve to minimize response times and reduce manpower requirements. BKV operates a steady and robust workover program, constantly reviewing candidate wells and maintaining a queue of prioritized jobs that provide economic and accretive production uplift. We operate a fleet of over 700 gas lift and wellhead compression units with real time optimization of this fleet. Ensuring our compressors are optimized for each specific facility allows us to maximize production and reduce costs. Other elements of our base management excellence include automated data collection and analysis processes, including well reviews, surveillance dashboards, and process change alerts. Additionally, we monitor and mitigate pipeline pressures, evaluate and implement compression and pressure reduction projects jointly with our midstream partners. We seek to prudently manage and lower operating costs through, for example, purchasing and operating our own slickline units, bringing various maintenance activities in-house which are traditionally third party, negotiating and signing longer term supply and vendor contracts, establishing strategic and advantageous procurement partnerships, leveraging basin scale to achieve organizational and purchasing efficiencies, and maintaining an efficient organizational structure with high performing teams.

Natural Gas Midstream

Our natural gas midstream operations support our upstream assets as well as generate incremental revenue via gathering, processing and transportation of third-party production. In the Barnett, we have extensive infrastructure with capacity across the field and limited additional capital required to connect our wells. Our midstream system in the Barnett operates at low pressure with only approximately 50% utilization as of June 30, 2024. In the Barnett, during the six months ended June 30, 2024, approximately 193 MMcf/d of our gross production volumes (approximately 22% of our total gross Barnett production) were gathered and processed by our owned Barnett midstream system, with our remaining Barnett production primarily under an agreement with EnLink with no minimum volume commitments. Our owned Barnett midstream system includes approximately 778 miles of gathering pipeline, 65 gas compression units and one amine processing unit.

In NEPA, for the six months ended June 30, 2024, our gross operated production volumes were approximately 125.2 MMcf/d. The volumes flow into third-party gatherers in the following proportions:

- Williams Companies ("Williams"): 51%
- UGI Energy Services Midstream Services ("UGI"): 40%
- Energy Transfer LP ("Energy Transfer"): 9%

Our owned and operated NEPA midstream system includes approximately 16 miles of gas gathering pipelines, 14 miles of freshwater distribution pipelines and six gas compression units in NEPA. As part of our sale of BKV Chaffee, we sold our minority non-operated ownership interest in a Repsol Oil & Gas operated midstream system in NEPA on June 14, 2024.

Gas Gathering & Processing Agreements

The majority of our gross operated production volumes in NEPA are contractually further gathered and treated by three main third parties. As of June 30, 2024, approximately 51%, 40% and 9% of our gross operated volumes in NEPA were further gathered and treated on Williams, UGI and Energy Transfer gathering systems, respectively. We have secured these services through acreage dedications, pursuant to which current and future production sourced from the specific acreage positions designated in each contract is required to be gathered and treated by each specific entity. Some of our NEPA gas gathering and processing contracts contain limited minimum volume commitment terms ("MVCs"), the earliest of which expire in the first quarter of 2025 and the second quarter of 2029. As of June 30, 2024, such MVCs require us to deliver 36 MMcf/d of natural gas, a majority of which flows into 82 MMcf/d of MVC related the gathering, central delivery point aggregation and intra-basin transport, which represented 76% of the gross volumes produced from covered acreage. Overall, the acreage dedication approach, coupled with limited MVCs, provides us strategic flexibility while also securing access to gathering, processing and transportation services. The use of third parties to contractually perform gathering and treating services also negates capital spending requirements for these services and allows us to focus our efforts and capital spend on our core energy and production business.

The terms of these contracts range from 10 and 20 years from original execution date, with an average term of four years remaining between the various contracts, as of June 30, 2024. The specified rates within these contracts are generally escalated annually subject to a standard Consumer Price Index escalator. These gathering and treating contracts offer deliverability to intra-basin markets, as well as multiple downstream pipelines that offer access to inter and intra-regional markets. This flexibility ultimately provides sufficient liquidity and market optionality that help facilitate the overall process of maximizing corporate netbacks.

For the assets we acquired in the Devon Barnett Acquisition, approximately 99% of our natural gas is gathered and transported by EnLink through various contracts that govern the services provided for the Bridgeport, Ponder and Jarvis systems. The Bridgeport system consists of both rich and lean gas governed by a market-rate based contract, as amended, with a term expiring in 2033. The gathering and processing fees under the Bridgeport contract contain an incentive mechanism pursuant to which we can achieve lower rates through refractured or new wells. All NGLs under the Bridgeport contract are sold to EnLink at Mont

Belvieu pricing subject to a market-based transport and fractionation differential. There are no MVCs associated with the natural gas gathering agreements for the assets we acquired in the Devon Barnett Acquisition.

For the assets we acquired in the Exxon Barnett Acquisition, approximately 90% of our natural gas is gathered and transported through an agreement assigned to our subsidiary, BKV Midstream, through various market-rate based contracts that take lean gas to various delivery points into Energy Transfer's pipeline. All gas currently flows to Energy Transfer, where BKV is under an acreage dedication for its downstream takeaway. We have one MVC related to the assets acquired in the Exxon Barnett Acquisition for less than $1.0 million per year, which MVC is currently unfulfilled and results in immaterial unutilized gathering charges. However, produced gas that can currently flow through this contract and fulfill the MVC has been rerouted and now flows through BKV's (formerly XTO Energy, Inc.'s) owned and operated gathering and compression facilities. The decision to construct the facilities, reroute this gas and strand the MVC-based contract was based upon superior economics and results in lower overall gathering and compression fees, even with the inclusion of the unutilized gathering charges. The MVC-based contract expires in the third quarter of 2024.

Power Generation

We have a 50% ownership interest in the BKV-BPP Power Joint Venture, which owns the Temple Plants, newly-constructed, modern combined cycle gas and steam turbine power plants located in the ERCOT North Zone in Temple, Texas. The remaining 50% interest is owned by BPPUS, a wholly owned subsidiary of Banpu Power and an affiliate of our sponsor, Banpu.

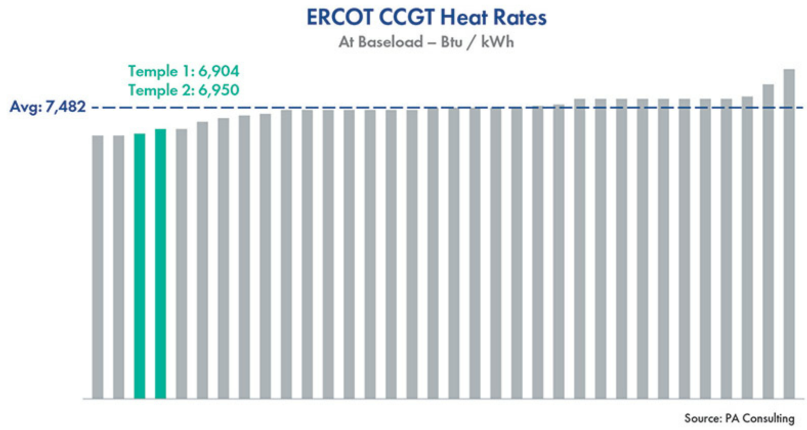
Power generation output from the Temple Plants is sold into the competitive wholesale bulk power market managed by ERCOT, Texas' electrical grid operator. ERCOT currently provides electric power to approximately 23 million people in Texas, with its customers using about 85% of the state's electric power. The operating flexibility of the Temple Plants provides significant competitive advantages in the ERCOT market. On a combined basis, the Temple Plants can generate and supply the power needs of approximately 1.5 million households in central Texas.

Operational since July 2014 and May 2015, the modern technology utilized at the Temple Plants enables them to respond to rapidly changing market signals in real time, making the power plants well-suited to serve the various needs of the ERCOT market. Temple I and Temple II have an average power generation capacities of 752 MW and 747 MW, respectively. Key equipment at the Temple Plants includes Siemens natural gas combustion turbine generators and steam turbine generators, as well as Benson heat recovery steam generators. The electrical transmission interconnection at Knob Creek Substation has minimal to moderate congestion risk. The Temple Plants typically undergo seasonal maintenance outages in spring and fall to ensure the highest operational readiness during the time when electricity consumption peaks (in winter and summer).

Temple I remained online at full capability during the historic February 2021 Winter Storm Uri and has since implemented incremental upgrades. Temple I has invested $836,117, with an additional $275,000 for each of Temple I and Temple II in planned weatherization expenditures for 2023, in each case to construct winterization enclosures, add insulation, and install heat tracing systems and back-up generators to provide freeze protection around at-risk piping, equipment and instrumentation in the power plant and gas yard. Additionally, wet compression systems were installed at Temple I and Temple II in July 2021 and July 2023, respectively, to increase each facility's output while operating in high ambient temperatures. Wet compression systems allow a larger volume of air to be compressed before being fed into the combustion process along with natural gas, thus increasing generation capacity during summer, the time when the ERCOT market's power demand typically peaks.

The Temple Plants deploy modern CCGT technology, which combines the working process of gas combustion, turbine and steam turbine generation. They are also some of the more flexible CCGTs supplying power to the ERCOT system due to their ability to achieve 50% production within 10 minutes and full baseload capacity within 30 minutes. Temple I and Temple II have baseload design heat rates of approximately 6,904 Btu/kWh and 6,950 Btu/kWh, respectively, which are below the ERCOT CCGT average, as shown in the chart below. Equipped with pollution control management systems to maintain low emissions, the Power Plants' efficient and flexible operations help maintain their competitive position in the ERCOT market.

The following chart summarizes the realized heat rate of the Temple Plants, as compared to other CCGT in ERCOT.



We expect our power generation assets will be synergistic with our base upstream business and we leverage our existing organization to provide marketing, engineering, finance, accounting and other administrative services to the BKV-BPP Power Joint Venture for an annual fee plus expenses. In addition, after receiving the necessary approvals from the PUCT and ERCOT, the BKV-BPP Power Joint Venture recently launched a retail marketing business to sell electricity to commercial, industrial, and residential retail customers in Texas through its wholly owned subsidiary, BKV-BPP Retail, under the brand name BKV Energy. Since its official launch in February 2023, BKV Energy has built a portfolio of over 57,000 customers and is licensed to serve throughout the deregulated portions of Texas.

In addition to 200,000 MMBtu/d of firm transportation services with Atmos and Energy Transfer and its subsidiaries, BKV-BPP Power's Bammel storage contract with Energy Transfer provides Temple I up to 2.8 Bcf of natural gas storage capacity, providing daily gas supply operating flexibility. The firm transportation and storage contracts with Energy Transfer and its subsidiaries also grant BKV-BPP Power the option to purchase and store in reserve excess natural gas, which can be released at times when gas prices are potentially higher, such as during seasonal price cycles or times of scarcity. Moreover, the potential to utilize our midstream assets to deliver and optimize natural gas feedstock to the power plants and to expand our CCUS business by sequestering post combustion CO_2 from the power plants are additional vertical integration opportunities that we intend to explore over time.

We believe we can create a differentiated offering to strategic buyers, retail and industrial customers. For more information about the risks involved in our retail power business, see "*Risk Factors — Risks Related to Our Retail Power Business*."

BKV-BPP Power Limited Liability Company Agreement

The Temple Plants are owned by Temple Generation Intermediate Holdings II, LLC, which is owned 100% by BKV-BPP Power, which, in turn, is owned 50% by us and 50% by BPPUS, a wholly owned subsidiary of Banpu Power. See "*— Our Relationship with Banpu*" and "*Certain Relationships and Related Party Transactions*."

We and BPPUS are each a party to the BKV-BPP Power LLC Agreement governing the BKV-BPP Power Joint Venture, which, among other things, provides that a general manager appointed by the Power JV Board will have the power to manage and administer the business and affairs of BKV-BPP Power, subject to specified matters reserved for approval by the Power JV Board. The appointment and removal of the general manager must be approved by both the Power JV Board and BPPUS. Transfer or encumbrance of a party's interest in BKV-BPP Power is permitted without prior approval of the other party or the Power JV Board. However, no transfer will be permitted if the transfer: (A) would subject BKV-BPP Power to U.S. federal securities law reporting requirements, (B) would cause BKV-BPP Power to lose its status as a U.S. partnership for federal income tax purposes or will cause BKV-BPP Power to be classified as a "publicly traded partnership," (C) would violate, give rise to a default under or cause any payment to become due under any credit agreement, guaranty, or similar credit document or any other material contract to which BKV-BPP Power or any affiliate is bound, or (D) occurs prior to the repayment by BKV-BPP Power of all loans and other amounts outstanding under the term loans.

In the event that either party admits in writing that it is unable to perform its obligations (including any obligation to provide additional capital contributions) under the BKV-BPP Power LLC Agreement, the non-defaulting party will be entitled to (i) sell the assets of the joint venture and dissolve the joint venture on reasonable terms deemed acceptable to the Power JV Board, (ii) obtain specific performance of the non-defaulting party's obligations, and/or (iii) exercise any other right or remedy provided in law or in equity. The Power JV Board will determine the amount and timing of distributions of operating cash flow (which will be done no less frequently than once per quarter) and net capital proceeds (which will be distributed within three business days after becoming available for distribution). All distributions will be made on a pro-rata basis to us and BPPUS. During the year ended December 31, 2023, BKV-BPP Power made a distribution to BKV Corp and BPPUS of $10.0 million to each member. For the six months ended June 30, 2024 and 2023 and for the years ended December 31, 2022 and 2021, no distributions were made by BKV-BPP Power or BKV-BPP Cotton Cove.

Additional cash capital contributions will be required to be made by us and by BPPUS on a pro-rata basis upon 30 days written notice either by us or by BPPUS; provided that the additional contributions must be expended on items included in the annual approved budget, items in response to an emergency in the event that BKV-BPP Power does not have sufficient cash reserves to address such emergency, or any other matter approved by the Power JV Board. Otherwise, neither us nor BPPUS will be required to provide additional capital contributions without consent.

Major decisions and significant activities of BKV-BPP Power are reserved for approval by at least a majority of the members of the Power JV Board, such as, among other things, any merger, consolidation, amalgamation, conversion of BKV-BPP Power or any of its subsidiaries, into another form or entity or other business combination of any nature, wind up, the dissolution, liquidation, commencement or any filing or petition for a voluntary bankruptcy, reorganization, debt arrangement involving BKV-BPP Power, any plan to or initial sale of BKV-BPP Power or other equity interests to the public, any amendments, restatements or revocations of its organizational documents, execution, amendment or termination of a material contract, and any amendment to or deviation from the dividend policy of the joint venture or any of its subsidiaries. Under the terms of the BKV-BPP Power LLC Agreement:

- we do not have the power to unilaterally cause BKV-BPP Power to make distributions;
- we may be required to make additional capital contributions to fund items approved in the annual budget or other matters approved by the Power JV Board at the request of BPPUS, which would reduce the amount of cash otherwise available for dividend payments by us on our common stock or require us to incur additional indebtedness; and
- BKV-BPP Power may incur additional indebtedness in an amount greater than $1,500,000 if approved by the Power JV Board, which debt payments would reduce the amount of cash that might otherwise be available for distributions to us.

Temple II Acquisition Financing

On July 10, 2023, Temple Generation Intermediate Holdings II, LLC ("Temple Borrower"), a subsidiary of BKV-BPP Power, entered into a Credit Agreement (the "Temple II Credit Agreement") with the lenders party thereto, administrative agent and collateral agent, which was comprised of (i) a senior secured term loan facility in an aggregate principal amount of $500.0 million, (ii) a senior secured revolving credit facility in an aggregate principal amount of $60.0 million and (iii) a letter of credit facility. Also on July 10, 2023, Temple Borrower borrowed an aggregate amount of $560.0 million under the Temple II Credit Agreement for purposes of, among other things, paying the consideration for the acquisition of Temple II and working capital and general corporate purposes. Under the Temple II Credit Agreement, the lenders have no recourse to us with respect to any amounts owed to them thereunder and we are not liable in any manner (and are not required to provide security) for any obligations owed to them thereunder.

Carbon Capture, Utilization and Sequestration

Through our CCUS business, we aim to reduce man-made GHG emissions to the atmosphere by capturing CO_2 emitted in connection with natural gas activities, whether from our own operations or third-party operations, as well as from other energy and industrial sources. Our process involves capturing CO_2 before it is released into the atmosphere and then compressing the captured CO_2 and transporting it via pipeline to sites where it can be injected into UIC wells for secure geologic sequestration. Additionally, we have engaged Project Canary to analyze and report the CO_2e injection volumes and environmental attributes of our sequestration projects, and we are working with the American Carbon Registry to certify and register the environmental attributes associated with our CCUS projects as tradeable carbon credits. In the future, we may sell carbon credits associated with our CCUS projects to unrelated third parties outside of our value chain, which may negatively impact our net zero strategy, including by delaying or preventing our achievement of net zero.

Although we formally launched our CCUS business in March 2022 with the establishment of BKV dCarbon Ventures, we have been evaluating project opportunities and developing our CCUS business since early 2021. The development of our CCUS business has progressed rapidly, supported by internal geology, engineering, operations, business development, land, regulatory and other professionals, along with academics and CCUS-focused partnerships. We believe that with a continued and timely execution of our business plans, the Barnett Zero Project could begin generating positive net income via tax credits in 2024. We expect to fund up to 50% of our CCUS business from a variety of external sources, which may include joint ventures, project-based equity partnerships and federal grants, with the remaining capital needs being funded with cash flows from operations. The projected timeline for commercial operations and the generation of positive CCUS business revenue and positive earnings depends, in part, on our ability to fund the anticipated capital requirements for the potential projects that we have identified and described above through external funding and revenues from our upstream business, as well as on our ability to receive our portion of the anticipated Section 45Q tax credits associated with these projects. We may not receive 100% of the Section 45Q tax credits associated with projects funded by third parties and, in such cases, will receive only a corresponding percentage of the anticipated Section 45Q tax credits associated with such projects.

We seek to execute CCUS projects with attractive standalone economics and the ability to sequester emissions from both our own operations and from third-party operations. For example, we plan to target CCUS projects with high concentration CO_2 streams where revenue, taking into account tax incentives, less cash operating expense would generally be expected to be between $40 and $70 per metric ton of sequestered CO_2e for the first six years of commercial operations for projects owned by BKV. We may also provide development and support services for third-party owned CCUS projects on a fee-for-service model, although such projects will not be included in our path to net zero. We are also evaluating potential third party investments in our CCUS business, which may accelerate the development of our CCUS projects; however, depending on the terms of such investment, this may impact the ultimate number of carbon credits we may receive from such projects.

As part of our “closed-loop” approach to our net zero emissions goal, we expect to apply a portion of the CO_2 emissions that are sequestered through our CCUS business to offset GHG emissions from our owned and operated upstream and natural gas midstream businesses. We may not receive 100% of the environmental attributes associated with CCUS projects funded in whole or in part by third parties, and, in such cases, we expect to have the right to purchase such environmental attributes BKV would not otherwise receive. Ultimately, we will be able to apply only such portion of the sequestered emissions to offset our own GHG emissions that corresponds to the percentage of environmental attributes BKV receives or purchases. We expect our CCUS business to contribute in significant part to our goals to fully offset our Scope 1 and 2 emissions from our owned and operated upstream and natural gas midstream businesses by the early 2030s, and our Scope 1, 2 and 3 emissions from our owned and operated upstream and natural gas midstream businesses by the late 2030s. See “— *Overview — Our Operations — Path to Net Zero Emissions*” for a description of how we estimate our Scope 1, 2 and 3 annual emissions and how we expect our CCUS business to contribute to the offset of those emissions.

Currently, we have one operational CCUS project and are pursuing sixteen additional potential CCUS projects that we believe are commercially viable based on economics supported by enhanced Section 45Q tax credits and that we believe can be completed by the late 2030s. For additional information about these projects, see "*— Overview — Our Operations — Carbon Capture, Utilization and Sequestration*."

Summary of Our Reserves Estimates

Ryder Scott, our independent petroleum engineers, prepared estimates of our natural gas, NGL and oil reserves as of December 31, 2023, 2022 and 2021. These reserves estimates were prepared in accordance with the rules and regulations of the SEC regarding oil and natural gas reserves reporting using SEC Pricing (except for the table that provides our estimated reserves as of December 31, 2023 at "NYMEX strip pricing" using pricing based on NYMEX future prices as of market close on December 31, 2023). For more information about our reserves volumes and values, see "*— Preparation of Reserves Estimates and Internal Controls*" and Ryder Scott's summary reserves reports, which are filed as exhibits to the registration statement of which this prospectus forms a part.

The following table provides our estimated proved reserves information prepared by Ryder Scott as of December 31, 2023, 2022 and 2021 and PV-10 Value and the Standardized Measure for each period. The decrease in our proved reserves and the PV-10 Value of those reserves as of December 31, 2023, as compared to December 31, 2022, is primarily due to lower commodity pricing. The increase in our proved reserves and the PV-10 Value of those reserves as of December 31, 2022, as compared to December 31, 2021, was primarily due to the Exxon Barnett Acquisition that we consummated on June 30, 2022. There are numerous uncertainties inherent in estimating quantities of natural gas, NGL and oil reserves and their values, including many factors beyond our control. See "*Risk Factors — Risks Related to Our Upstream Business and Industry — Our estimated natural gas, NGL and oil reserves quantities and future production rates are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in the reserves estimates or the underlying assumptions will materially affect the quantities and present value of our reserves.*" For more information about our proved reserves, see "*— Preparation of Reserves Estimates and Internal Controls*" and Ryder Scott's summary reserves reports, which are filed as exhibits to the registration statement of which this prospectus forms a part.

Estimated Reserves at SEC Pricing[(1)]

	December 31,		
	2023	2022	2021
Estimated proved developed reserves:			
Natural gas (MMcf)	2,443,072	3,798,019	2,494,925
Producing	2,290,025	3,468,896	2,346,712
Non-producing	153,047	329,123	148,213
Natural gas liquids (MBbls)	156,399	170,840	151,433
Producing	129,260	157,585	142,961
Non-producing	27,139	13,255	8,472
Oil (MBbls)	992	1,111	867
Producing	802	1,111	867
Non-producing	190	—	—
Total estimated proved developed reserves (MMcfe)	3,387,418	4,829,733	3,408,725
Producing	3,070,397	4,421,072	3,209,680
Non-producing	317,021	408,653	199,045
Standardized Measure (millions)	$ 986	$ 5,809	$ 2,119
PV-10 (millions)[(2)(3)]	$ 1,151	$ 7,389	$ 2,672

	December 31,		
	2023	2022	2021
Estimated proved undeveloped reserves:			
Natural gas (MMcf)	539,423	1,057,657	950,358
Natural gas liquids (MBbls)	27,766	40,660	13,722
Oil (MBbls)	59	758	58
Total estimated proved undeveloped reserves (MMcfe)(4)(5)	706,373	1,306,157	1,033,038
Standardized Measure (millions)	$ 48	$ 1,185	$ 295
PV-10 (millions)(2)(6)	$ 81	$ 1,566	$ 403
Estimated total proved reserves:			
Natural gas (MMcf)	2,982,495	4,855,676	3,445,283
Natural gas liquids (MBbls)	184,165	211,500	165,155
Oil (MBbls)	1,051	1,869	925
Total estimated proved reserves (MMcfe)	4,093,791	6,135,890	4,441,763
Standardized Measure (millions)	$ 1,034	$ 6,994	$ 2,414
PV-10 (millions)(2)(7)	$ 1,232	$ 8,955	$ 3,075

(1) Prices for natural gas, oil and NGLs, respectively, used in preparing our estimated proved reserves and the associated PV-10 Value based on SEC Pricing (i) at December 31, 2023 were $2.637 per MMBtu (Henry Hub), $78.22 per Bbl (WTI Cushing) and NGL pricing equal to 29.5% of WTI Cushing, (ii) at December 31, 2022 were $6.358 per MMBtu (Henry Hub), $93.67 per Bbl (WTI Cushing) and NGL pricing equal to 36.7% of WTI Cushing and (iii) at December 31, 2021 were $3.598 per MMBtu (Henry Hub), $66.56 per Bbl (WTI Cushing) and NGL pricing equal to 39.5% of WTI Cushing.

(2) PV-10 refers to the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect at the determination date, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%. PV-10 is not a financial measure calculated in accordance with GAAP because it does not include the effects of income taxes on future net revenues. PV-10 is derived from the Standardized Measure, which is the most directly comparable GAAP financial measure. Neither PV-10 nor Standardized Measure represent an estimate of the fair market value of our oil and natural gas properties. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and gas properties. It is not intended to represent the current market value of our estimated reserves. PV-10 should not be considered in isolation or as a substitute for the Standardized Measure reported in accordance with GAAP, but rather should be considered in addition to the Standardized Measure. See "*Prospectus Summary —Summary Reserves, Production and Operating Data*."

(3) The following table provides a reconciliation of the Standardized Measure to PV-10 with respect to estimated proved developed reserves as of December 31, 2023, 2022 and 2021:

	December 31,		
	2023	2022	2021
PV-10 (millions)	$1,151	$ 7,389	$2,672
Present value of future income taxes discounted at 10%	(165)	(1,580)	(553)
Standardized Measure	$ 986	$ 5,809	$2,119

(4) Proved undeveloped reserves as of December 31, 2023 are part of a development plan that has been adopted by management indicating that such locations are scheduled to be drilled within five years. Proved undeveloped reserves as of December 31, 2022 and 2021 were part of a development plan adopted by management indicating that such locations were scheduled to be drilled within five years of initial booking.

(5) Sustained lower prices for oil and natural gas may cause us to forecast less capital to be available for development of our proved undeveloped reserves, which may cause us to decrease the amount of our proved undeveloped reserves we expect to develop within the allowed time frame. In addition, lower oil and natural gas prices may cause our proved undeveloped reserves to become uneconomic to develop, which would cause us to remove them from their respective reserves category.

(6) The following table provides a reconciliation of the Standardized Measure to PV-10 with respect to estimated proved undeveloped reserves as of December 31, 2023, 2022 and 2021:

	December 31,		
	2023	2022	2021
PV-10 (millions)	$ 81	$1,566	$ 403
Present value of future income taxes discounted at 10%	(33)	(381)	(108)
Standardized Measure	$ 48	$1,185	$ 295

(7) The following table provides a reconciliation of the Standardized Measure to PV-10 with respect to estimated proved reserves as of December 31, 2023, 2022 and 2021:

	December 31,		
	2023	2022	2021
PV-10 (millions)	$1,232	$ 8,955	$3,074
Present value of future income taxes discounted at 10%	(198)	(1,961)	(661)
Standardized Measure	$1,034	$ 6,994	$2,413

During the years ended December 31, 2023, 2022 and 2021, we incurred costs of approximately $37.7 million, $54.0 million and $7.2 million, respectively, to convert 31.9 Bcfe, 74.0 Bcfe and 19.4 Bcfe, respectively, of proved undeveloped reserves to proved developed reserves. Estimated future development costs relating to the development of our proved undeveloped reserves at December 31, 2023, 2022 and 2021 are approximately $356.2 million, $1,089.6 million and $578.3 million, respectively, over the next five years, substantially all of which we expect to finance through cash flow from operations and/or borrowings under our RBL Credit Agreement. Our development programs through the year ended December 31, 2023 focused on refracturing under-stimulated wells and designing and drilling new wells in both our Barnett and NEPA assets. Our proved undeveloped reserves, as of December 31, 2023, are scheduled to be developed within five years of their initial disclosure. See "*Risk Factors — Risks Related to Our Upstream Business and Industry — The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate.*"

Natural gas prices decreased significantly during 2023 and are projected to remain lower than the near-record high prices experienced in 2022. Due to our desire to be a prudent operator and exercise capital discipline in this pricing environment, subsequent to finalizing our reserve reports as of December 31, 2023, we decreased our capital expenditures budget for development of natural gas properties for 2024 to approximately $13.0 million from our original budget of approximately $73.0 million, which was the amount applied in connection with the preparation of the estimates of our reserves as of December 31, 2023. We estimate that this reduction in our 2024 capital expenditures would result in a decrease in our proved reserves, standardized measure value of proved reserves, and the PV-10 value of proved reserves as of December 31, 2023 by approximately 3.3%, 1.6%, and 2.0%, respectively. If the current lower natural gas commodity pricing environment extends beyond 2024, we will continue to maintain capital discipline and reflect corresponding capital expenditure changes in our estimated reserves. These changes would mainly impact proved undeveloped reserves and proved developed non-producing reserves, which collectively represent approximately 25% of our total estimated proved reserves as of December 31, 2023.

2023 Activity

During the year ended December 31, 2023, the Company's proved reserves decreased by 2,042.1 Bcfe. The decrease in proved reserves was primarily attributable to decreased commodity pricing and changes in the Company's drilling activity, which resulted in total downward revisions of 1,986.3 Bcfe. As discussed below, these decreases were partially offset by extensions and discoveries and improved recoveries experienced by the Company in 2023, which resulted in net increases to proved reserves of 227.8 Bcfe and 30.2 Bcfe, respectively. The Company produced 313.8 Bcfe during the year ended December 31, 2023.

Revisions of previous estimates primarily consisted of downward revisions to proved developed reserves and proved undeveloped reserves of 1,191.9 Bcfe and 273.1 Bcfe, respectively, as a result of lower average pricing during 2023 for natural gas, NGLs, and oil. Additional downward revisions were made to proved undeveloped reserves of 521.3 Bcfe due to the Company's lower capital spend and the resulting reduction in drilling activity during 2023. Changes to the Company's drilling schedule moved the development of 112.0 gross (104.6 net) locations in NEPA and the Barnett beyond the SEC requirement of developing PUDs five years from initial booking. These 112.0 gross (104.6 net) locations remain in the Company's inventory of unproved locations to be developed outside of the next five years. The drilling schedule changes reflect the Company's ongoing commitment to optimize the long-term plan to best develop its assets, maximize cash flow, and produce economic returns.

Extensions and discoveries primarily consisted of 226.5 Bcfe of proved undeveloped reserves, of which 197.8 Bcfe was attributable to 22.0 gross (21.2 net) locations recognized as a result of the Company's optimized drilling program, which reduced costs and extended lateral lengths. In addition, 28.7 Bcfe was attributable to extensions related to 3.0 gross (1.1 net) locations in NEPA. Our unitization and combination of acreage with Repsol resulted in the three additional locations.

Improved recoveries consisted of 30.2 Bcfe of proved developed reserves recognized as a result of the application of improved recovery techniques to producing wells during the year ended December 31, 2023.

Conversions of proved undeveloped reserves to proved developed reserves consisted of 31.9 Bcfe related to the completion of 22.0 gross (8.1 net) wells on proved undeveloped locations during the year ended December 31, 2023.

2022 Activity

During the year ended December 31, 2022, the Company's proved reserves increased by 1,694.1 Bcfe. The increase in proved reserves was primarily due to the acquisition of the 2022 Barnett Assets. Other factors that contributed to the increase in proved reserves during 2022 included increasing commodity pricing, which improved economics, improved recoveries due to the application of restimulation technology to producing wells and the addition of NGL rich locations to the drilling schedule. The Company produced 279.5 Bcfe during the year ended December 31, 2022.

Revisions of previous estimates consisted of upward revisions to proved developed reserves of 182.9 Bcfe as a result of higher average pricing during 2022 for natural gas, NGLs and oil. An additional upward revision of 52.0 Bcfe was made to proved developed reserves for performance adjustments. Upward revisions were offset by downward revisions to proved undeveloped reserves of 246.0 Bcfe relating to 76.0 gross (53.1 net) locations in NEPA and the Barnett that were removed from the drilling schedule in exchange for locations with more favorable economics, as discussed in the following explanation of extensions and discoveries in 2022. Additional downward revisions of 67.3 Bcfe and 42.9 Bcfe were made to proved undeveloped reserves related to performance and increased development costs, respectively.

Extensions and discoveries primarily consisted of the addition of 389.5 Bcfe of proved undeveloped reserves from 71.0 gross (66.4 net) locations recognized as a result of our revised evaluation of properties acquired through our Devon Barnett Acquisition. The added locations are more rich in NGLs than the previously recognized locations that were removed from the 2021 drilling schedule, as discussed in the preceding explanation of revisions of previous estimates in 2022. Additional extensions consisted of proved undeveloped reserves of 85.8 Bcfe related to 27.0 gross (12.8 net) locations in NEPA and the Barnett that were recognized from acreage acquired in 2021 and as a result of the revised 2022 drilling plan. Extensions related to proved developed reserves of 74.1 Bcfe consisted of 23.0 gross (13.0 net) newly drilled wells on locations previously classified as unproved.

Purchases of minerals in place consisted of 1,237.1 Bcfe and 227.9 Bcfe of proved developed and proved undeveloped reserves, respectively, from the Exxon Barnett Acquisition. The acquired reserves consisted of operated working interests in 2,289.0 gross (1,696.4 net) wells and 53.0 gross (48.7 net) undeveloped locations.

Improved recoveries consisted of 80.5 Bcfe of proved developed reserves recognized as a result of the application of improved recovery techniques to producing wells during the year ended December 31, 2022.

Conversions of proved undeveloped reserves to proved developed reserves consisted of 73.9 Bcfe related to the completion of 19.0 gross (5.5 net) wells on proved undeveloped locations during the year ended December 31, 2022.

2021 Activity

During the year ended December 31, 2021, the Company's proved reserves increased by 1,808.5 Bcfe. The increase in proved reserves was primarily due to increasing commodity pricing improving economics, and additions to the drilling schedule for both proved developed and undeveloped reserves. The Company produced 245.8 Bcfe during the year ended December 31, 2021.

Revisions of previous estimates primarily consisted of upward revisions to proved developed reserves and proved undeveloped reserves of 715.9 Bcfe and 245.6 Bcfe, respectively, as a result of higher average pricing during 2021 for natural gas, NGLs and oil. The remaining upward adjustment of 139.8 Bcfe relates to upward performance adjustments of 219.2 Bcfe to proved developed reserves offset by a downward revision of 79.4 Bcfe to proved developed reserves due to increased production costs.

Extensions and discoveries increased as a result of the completion of our evaluation of properties acquired through our Devon Barnett Acquisition, 550.1 Bcfe of proved undeveloped reserves was recognized for 123.0 gross (94.8 net) locations added to the Company's revised drilling schedule during 2021. Additional extensions consisted of proved undeveloped reserves of 162.5 Bcfe related to 13.0 gross (9.6 net) locations in NEPA recognized from acquired acreage and the revised 2021 drilling plan. Extensions related to proved developed reserves of 15.4 Bcfe consisted of 10.0 gross (3.0 net) newly drilled wells.

Purchases of minerals in place consisted of 17.7 Bcfe of proved developed reserves from the acquisition of additional working interests in 601.0 gross (14.6 net) wells and 1.8 Bcfe of proved undeveloped reserves from the acquisition of additional working interests in 18.0 gross (1.0 net) locations, each of which were in addition to the Company's previously held working interests in wells or working interests in locations in the Barnett.

Improved recoveries consisted of 205.4 Bcfe of proved developed reserves recognized as a result of the application of improved recovery techniques to producing wells during the year ended December 31, 2021.

Conversions of proved undeveloped reserves to proved developed reserves consisted of 19.4 Bcfe related to the completion of 4.0 gross (3.9 net) wells on proved undeveloped locations during the year ended December 31, 2021.

Estimated Reserves at NYMEX Strip Pricing

The following table provides our total estimated proved reserves information prepared by Ryder Scott as of December 31, 2023, using NYMEX strip prices as of market close on December 31, 2023 and PV-10 Value and the Standardized Measure for such period. We have included this information in order to provide an additional method of presentation of the fair value of our assets and the cash flows that we expect to generate from those assets based on the market's forward-looking pricing expectations as of December 31, 2023. The historical 12-month pricing average in our December 31, 2023 disclosures above does not reflect the prevailing natural gas and oil futures. We believe that the use of forward prices provides investors with additional useful information about our reserves, as the forward prices are based on the market's forward-looking expectations of natural gas and oil prices as of a certain date, although we caution investors that this information should be viewed as a helpful alternative, not a substitute, for the data presented based on SEC Pricing. In addition, we believe that NYMEX strip pricing provides relevant and useful information because it is widely used by investors in our industry as a basis for comparing the relative size and value of our reserves to our peers. Our estimated reserves based on NYMEX futures were otherwise prepared on the same basis as our SEC reserves for the comparable period. Actual future prices may vary significantly from the NYMEX strip prices on December 31, 2023. Actual revenue and value generated may be more or less than the amounts disclosed. There are numerous uncertainties inherent in estimating quantities of natural gas, NGL and oil reserves and their values, including many factors beyond our control. See "*Risk Factors — Risks*

Related to Our Upstream Business and Industry — Our estimated natural gas, NGL and oil reserves quantities and future production rates are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in the reserves estimates or the underlying assumptions will materially affect the quantities and present value of our reserves."

	December 31, 2023
Estimated proved developed reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	2,984,949
Producing	2,791,791
Non-producing	193,158
Natural gas liquids (MBbls)	164,204
Producing	134,689
Non-producing	29,515
Oil (MBbls)	1,046
Producing	808
Non-producing	238
Total estimated proved developed reserves (MMcfe)	3,976,436
Producing	3,604,773
Non-producing	371,663
Standardized Measure (millions)	$ 1,651
PV-10 (millions)(1)	$ 2,015
Estimated proved undeveloped reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	790,838
Natural gas liquids (MBbls)	30,500
Oil (MBbls)	59
Total estimated proved undeveloped reserves (MMcfe)(2)(3)	974,192
Standardized Measure (millions)	$ 244
PV-10 (millions)(4)	$ 335
Estimated total proved reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	3,775,787
Natural gas liquids (MBbls)	194,704
Oil (MBbls)	1,105
Total estimated proved reserves (MMcfe)	4,950,628
Standardized Measure (millions)	$ 1,895
PV-10 (millions)(5)	$ 2,350

(1) The following table provides a reconciliation of the Standardized Measure to PV-10 (applying NYMEX Strip Pricing) with respect to estimated proved developed reserves as of December 31, 2023:

	December 31, 2023
PV-10 (millions)	$ 2,015
Present value of future income taxes discounted at 10%	(364)
Standardized Measure	$ 1,651

(2) Proved undeveloped reserves as of December 31, 2023 are part of a development plan that has been adopted by management indicating that such locations are scheduled to be drilled within five years.

(3) Sustained lower prices for oil and natural gas may cause us to forecast less capital to be available for development of our proved undeveloped reserves, which may cause us to decrease the amount of our proved undeveloped reserves we expect to develop within the allowed time frame. In addition, lower oil

and natural gas prices may cause our proved undeveloped reserves to become uneconomic to develop, which would cause us to remove them from their respective reserves category.

(4) The following table provides a reconciliation of the Standardized Measure to PV-10 (applying NYMEX Strip Pricing) with respect to estimated proved undeveloped reserves as of December 31, 2023:

	December 31, 2023
PV-10 (millions)	$ 335
Present value of future income taxes discounted at 10%	(91)
Standardized Measure	$ 244

(5) The following table provides a reconciliation of the Standardized Measure to PV-10 (applying NYMEX Strip Pricing) with respect to estimated proved reserves as of December 31, 2023:

	December 31, 2023
PV-10 (millions)	$ 2,350
Present value of future income taxes discounted at 10%	(455)
Standardized Measure	$ 1,895

Preparation of Reserves Estimates and Internal Controls

Our reserves estimates as of December 31, 2023, 2022 and 2021 included in this prospectus are based on reports prepared by Ryder Scott, our independent reserves engineer, in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC in effect at such time. We rely on Ryder Scott's expertise to ensure that our reserves estimates are prepared in compliance with SEC rules, regulations and disclosure guidelines and that appropriate geologic, petroleum engineering, and evaluation principles and techniques are applied in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers titled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of June 2019)." Copies of Ryder Scott's reserves reports are included as exhibits to the registration statement of which this prospectus forms a part.

The person at Ryder Scott responsible for the preparation of the reserves report is Stephen E. Gardner, a Licensed Professional Engineer in the State of Colorado (No. 44720). Mr. Gardner, an employee of Ryder Scott since 2006, is a Managing Senior Vice President responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Gardner served in a number of engineering positions with Exxon Mobil Corporation. Mr. Gardner earned a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001 (summa cum laude). He is a licensed Professional Engineer in the States of Colorado and Texas. Mr. Gardner is a member of the Society of Petroleum Engineers and a former chairperson of the Society of Petroleum Evaluation Engineers for the Denver Chapter. He also currently serves on the latter organization's board of directors at the international level. Mr. Gardner has attained the professional qualifications as a Reserves Estimator set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

Our internal staff of petroleum engineers, geoscience professionals, operations, land, finance and accounting, and marketing personnel prior to our annual reserves process, work closely together to ensure the integrity, accuracy and timeliness of data so that our reservoir engineering team can review such data and then furnish it to, and work with, our independent reserves engineers in their reserves evaluation process. Our internal reserves process follows a rigorous workflow where the multidisciplinary teams come together to vet our model assumptions and input and get final signoff before our technical team meets with the independent reserves engineers to review properties and discuss methods and assumptions used to prepare reserves estimates. Our Chief Technology Services Officer, Ethan Ngo, is primarily responsible for overseeing the independent reserves engineers during the process. Mr. Ngo has over 14 years of conventional and unconventional experience on and offshore across the lower 48 states with a major oil and gas company, independent oil and gas companies, and a private-equity-backed oil and gas company. Mr. Ngo has a BS in

Civil Engineering and Masters in Petroleum Engineering and International Political Economy of Resources from the Colorado School of Mines, and a MBA from the University of Colorado, Denver.

Ryder Scott relies on various data provided by our internal reservoir engineering team in preparing its reserves estimates, including such items as oil and natural gas prices, ownership interests, production information, operating costs, planned capital expenditures and other technical data. Our internal reservoir engineering team consists of qualified petroleum engineers who maintain our internal evaluation of reserves and compare our information to the reserves prepared by Ryder Scott. Management is responsible for designing the internal control procedures used in the preparation of our oil and gas reserves, which include verification of data input into reserves forecasting and economics evaluation software, as well as multi-discipline management reviews. The internal reservoir engineering team reports directly to our Senior Vice President of Engineering.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved behind pipe (proved developed non-producing) oil and gas reserves are new reserves that can be expected to be recovered through existing wells, active or shut-in, where expenditure is required to access the new reserves. Proved undeveloped oil and gas reserves are 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 completion. Proved undeveloped reserves on undrilled acreage are limited to those locations on development spacing areas that are offsetting economic producers that are reasonably certain of economic production when drilled. Proved undeveloped reserves for other undrilled development spacing areas are claimed only where it can be demonstrated with reasonable certainty that there is continuity of economic production from the existing productive formation. Proved undeveloped reserves are included only if a development plan has been adopted indicating that such locations are scheduled to be drilled within five years.

Uncertainties are inherent in estimating quantities of proved reserves, including many factors beyond our control. Reserves engineering is a subjective process of estimating subsurface accumulations of oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserves estimate is a function of the quality of available data and its interpretation. As a result, estimates by different engineers often vary, sometimes significantly. In addition, physical factors such as the results of drilling, testing, and production subsequent to the date of an estimate, as well as economic factors such as changes in product prices or development and production expenses, may require revision of such estimates. Accordingly, quantities of oil and natural gas ultimately recovered will vary from reserves estimates. See "*Risk Factors*" for a description of some of the risks and uncertainties associated with our upstream business and reserves.

Reserves estimates are based on production performance, data acquired remotely or in wells, and are guided by petrophysical, geologic, geophysical and reservoir engineering models. Estimates of our proved reserves were based on deterministic methods. In the case of mature developed reserves, reserves estimates are determined by decline curve analysis and in the case of immature developed and undeveloped reserves, by analogy, using proximate or otherwise appropriate examples in addition to volumetric and statistical analyses. The technologies and economic data used in estimating our proved reserves include empirical evidence through drilling results and well performance, well logs and test data, geologic maps and available surface and downhole pressure data, and production and reservoir data. Further, the internal review process of our wells and related reserves estimates includes but is not limited to the following:

- 3D seismic-based subsurface maps,
- Petrophysical estimates of original gas in place,
- Volumetric estimates for producing wells,
- Decline curve analysis,
- Rate transient and analytical model analysis,
- Statistical analysis and Monte Carlo simulation, and
- Fracture modeling.

Our estimated proved reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance. Regional variations in pricing and related deductions are similarly obtained and a 12-month average is calculated at year end.

For the years ended December 31, 2023, 2022 and 2021, Ryder Scott and our multidisciplinary team of technical and other professionals jointly reviewed our well performance and future development plans. Following that joint review, we furnished our internal reserves database and supporting data to Ryder Scott to facilitate their preparation of independent reserves estimates and final reports. Access to our database containing reserves information is restricted to select individuals from our engineering department.

Seasonality

Weather conditions have a significant impact on the demand for natural gas used for heating loads and natural gas-fired power generation. Demand for natural gas is generally at its lowest during the spring and fall months and peaks during the summer and winter months. Demand in the winter season peaks due to residential and commercial heating load demand, while the summer season peaks due to cooling loads, which calls on increased natural gas fired power generation loads. However, seasonal anomalies such as warmer than normal winters or cooler than normal summers can lessen the magnitude of the seasonal fluctuations in demand. In addition, natural gas storage facilities are utilized to bring additional supply to the market that is utilized to meet peak demand levels during both winter and summer seasons.

In addition to the demand side effects, specific seasonal weather events can also have an effect on available natural gas supply. In recent history, much colder than normal weather has induced wellhead freeze-offs in various regional supply markets, which ultimately lessens supply available to broader markets. Various weather events related to the summer months can similarly have detrimental effects on available supply also.

These seasonal anomalies can also increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations. Similarly, winter months may bring about delays in operational capabilities and efficiency of execution related to new and existing supply.

Enterprise Risk Management (ERM)

We have a standing risk management committee (“RMC”) which meets regularly and assesses, mitigates and provides direction on management of key enterprise risks. RMC members include executives and senior leaders within various functions such as legal, information technology, marketing, regulatory and sustainability, safety, security, operations, finance and accounting, and land.

COVID-19 Impact

Our supply chain has not experienced any significant interruptions as a result of the COVID-19 pandemic. The lack of a market or available storage for any one NGL product or oil could result in our having to delay or discontinue well completions and commercial production or shut-in production for other products because we cannot curtail the production of individual products in a meaningful way without reducing production of other products. Potential impacts of these constraints may include partial shut-in of production, although we are not able to determine the extent of shut-ins or for how long they may last. However, because some of our wells produce rich gas, which is processed, and some produce lean gas, which does not require processing, we can change the mix of products that we produce and wells that we complete to adjust our production to address takeaway capacity constraints for certain products. For example, we can shut-in rich gas wells and still produce from our lean gas wells if processing or storage capacity of NGL products becomes limited or constrained.

Customers and Product Marketing

We utilize an unaffiliated third party to market all of our natural gas and oil production to various purchasers, which consist of credit-worthy counterparties, including utilities, LNG producers, industrial consumers, major corporations and super majors, in our industry. This third party collects directly from the purchasers and remits to us the total of all amounts collected on our behalf less their fee for making such sales. We do not believe the loss of any customer would have a material adverse effect on our business, as other customers or markets are currently accessible to us.

Our ability to market oil and natural gas depends on many factors beyond our control, including the extent of domestic production and imports of oil and natural gas, available storage, the proximity of our natural gas and oil production to pipelines and corresponding markets, the available capacity in such pipelines, the demand for natural gas and oil, the effects of weather, and the effects of state and federal regulation. While we have not experienced significant difficulty in finding a market for our production as it becomes available or in transporting our production to those markets, there is no assurance that we will always be able to market all of our production or obtain favorable prices.

Marketing and Differentials

In NEPA, we continually monitor ongoing market dynamics to ensure equity gas sales are well positioned in terms of market optionality and counterparty liquidity. Within our operating area, sales are generally exposed to indices (denoted in parentheses) located on Eastern Gas Pipeline (South), Millennium Pipeline (East Pool), Tennessee Gas Pipeline (Zone 4) and Transco Pipeline (Leidy). From time to time, we will enter into longer-term commitments with downstream pipelines for firm transportation service. As of June 30, 2024, we have multiple contracts for firm transportation services including a combined 61,000 MMBtu/d to various locations on Tennessee Gas Pipeline and 27,500 MMBtu/d on Millennium Pipeline, which provide access to premium markets in New England (Algonquin), the Northeast and Gulf Coast areas. The remaining term on these contracts range from a few months to 12 years, with an average remaining duration of 4.5 years as of June 30, 2024.

In the Barnett, we have several firm transportation contracts specific to the Devon Barnett Acquisition to transport natural gas volumes out of the Barnett to premium markets, including 200,000 MMBtu/d to the Katy area, 200,000 MMBtu/d of intra-basin aggregation transport, which feeds 200,000 MMBtu/d of interstate transport to Transco Zone 4 Station 85, and 60,000 MMBtu/d to NGPL-TxOk with term end dates ranging through 2025 and 2029. We are currently negotiating extensions of several Barnett transportation agreements to preserve optionality to transport volumes out of the Barnett.

We were assigned 270,000 MMBtu/d of firm transport on Energy Transfer and Houston Pipe Line Company LP in connection with the closing of the Exxon Barnett Acquisition, which firm transport will expire in 2027. The contract with Energy Transfer and Houston Pipe Line provides access to the NGPL-TxOk market. Additionally, we executed a transaction confirmation with XTO Energy, Inc., which had the structural effect of assigning 170,000 MMBtu/d of firm capacity on Midcontinent Express Pipeline providing access to premium markets at Transco Zone 4 Station 85. Such contract expired on November 1, 2022 and BKV is currently negotiating to replace the expired capacity and maintain access to such markets.

As it relates to the Temple Plants, in addition to 2,812,500 MMBtu of storage at Energy Transfer's Bammel storage facility which expires in late 2027, BKV-BPP Power holds a combined 200,000 MMBtu/d of firm transport with Atmos and Energy Transfer and its subsidiaries which supports receipt of gas from the Katy Area with delivery to the Temple Facility and expires in late 2027. Additionally, Temple I holds 125,000 MMBtu/d of interruptible transport with Atmos Pipeline for delivery to Temple I, which terminates upon cancellation by the parties.

Unless otherwise mentioned, under all firm transportation contracts, we pay reservation fees, regardless of usage, to hold transportation rights of the contracted volume on these pipelines for the duration of the contract. As of June 30, 2024, our minimum aggregate required payments per year under firm gathering and transportation agreements are approximately $34.5 million for 2024, $68.2 million for 2025, $66.4 million for 2026, $58.6 million for 2027, $53.2 million for 2028 and $73.2 million for 2029 and beyond. The utilization and economic optimization of the upstream business units' firm transportation contracts are currently managed by Concord Energy, LLC, who acts as the marketing agent for all our upstream marketed volumes. We believe that all of our transport contracts for NEPA, the Barnett and the Temple Plants are at competitive rates.

Competition

The oil and gas industry is very competitive, and we compete with a substantial number of other companies, many of which are large, well-established and have greater financial and operational resources than we do. We compete with several other onshore unconventional natural gas producers to deliver our products to the marketplace, some of which include TotalEnergies and Lime Rock Resources (operating in the Barnett), Chesapeake Energy Corporation, Repsol USA, Coterra Energy Inc. and Southwestern Energy Company (operating in NEPA), among others.

Some of our competitors not only engage in the acquisition, exploration, development and production of oil and gas reserves and electricity generation, but also carry-on refining operations and the marketing of refined products. In addition, the oil and gas industry in general competes with other industries supplying energy and fuel to industrial, commercial and individual consumers, including alternative energy sources. Competition is particularly intense in the acquisition of prospective oil and gas properties. We may incur higher costs or be unable to acquire and develop desirable properties at costs we consider reasonable because of this competition. We also compete with other oil and gas companies to secure drilling rigs, frac fleets, sand and other equipment and materials necessary for the drilling and completion of wells and in the recruiting and retaining of qualified personnel. Such materials, equipment and labor may be in short supply from time to time. Shortages of equipment, labor or materials may result in increased costs or the inability to obtain such resources as needed. Many of our larger competitors may have a competitive advantage when responding to commodity price volatility and overall industry cycles. Further, inflation may affect us more than it may affect some of our larger competitors.

Ownership by our Directors and Officers in Other Entities

Most of our directors now own, or our officers and other directors may own in the future, stock and options to purchase stock in one or more of Banpu or its related companies. Additionally, our directors or officers may own disproportionate interests (in percentage or value terms) in Banpu or its related companies. These ownership interests and/or such disparity could create, or appear to create, potential conflicts of interest when the applicable individuals are faced with decisions that could have different implications for us, Banpu or its related companies.

Environmental, Health, Safety and Climate Change Considerations

We understand the impact climate change has on our community, the world and future generations, which is why addressing these impacts in how energy is produced is a top priority. In particular, it is one of our core values, “Be One BKV,” to create a unified team with a shared vision to achieve our emission reduction and energy impact goals.

We have established a Working Team consisting of a cross-functional group of BKV leaders who specialize in ESG strategy that meets periodically to identify, assess and implement critical ESG program initiatives. In addition, we have a Risk Management Committee that includes representatives from our operations, legal, finance, investor relations, information technology, marketing and environmental compliance teams and meets periodically to review potential ESG and other risks, tracks how these risks may be changing and ensures they are being properly managed. Our executive short-term incentive plan is tied to ESG-related initiatives, such as operational safety goals, social goals related to employee engagement and the establishment and implementation of our ESG program. In 2023, we achieved our operational safety goals by having zero major incidents (such as well control issues or explosions), having two regulatory violations and having four reportable incidents or injuries (TRIR 0.42). Also, in 2023, we exceeded our ESG program goals of reaching 110,000 Mtpy CO_2e in emissions reductions from our owned and operated upstream operations. The base-year emissions values established in 2021, and then reestablished in 2022 with the addition of the Exxon Barnett Acquisition have been utilized to measure our emission reduction progress and develop goals. To facilitate our emissions reduction goals, we are deploying our emissions monitoring ecosystem and executing our “Pad of the Future” and other emissions reduction programs. We utilized the upstream and natural gas midstream operations’ updated base-year emissions to refine and measure our emission reductions goals and progress, which include year-over-year step-down reduction projections through 2027. Through these efforts, as of December 31, 2023, we completed emission reducing conversions on 3,202 of the approximately 6,000 wells we plan to include in our “Pad of the Future” program by the end of

2027. Emissions reductions of over 380,000 Mtpy CO_2e that were attributable to our "Pad of the Future" program as of December 31, 2022, and reductions of over 130,000 Mtpy CO_2e as of December 31, 2023 are reflected in our updated emissions based on 2023 Subpart W reporting year's emissions.

We also have established robust Environmental, Health, Safety and Regulatory ("EHSR") goals with proven results. At the management level, our EHSR programs are overseen directly by our Chief Executive Officer and Chief Operating Officer. Our Senior Director of EHSR reports to our Chief Operating Officer, providing direct access to executive management and decision-making with respect to our top priority focus of EHSR performance. Our safety performance ranks high in comparison to our peers, and we have achieved a Total Recordable Incident Rate (TRIR) of zero in 2019 through 2021, a 0.21 in 2022 and a 0.42 in 2023, which includes both our employees and our contractors. Through December 31, 2023, our employees have driven, on average, a total of nearly 6,000,000 miles per year, during which time we have had two at-fault driving incidents. We recorded our first and second at-fault incidents in the first and second quarters of 2023, respectively. Regarding our environmental and safety performance, we have received zero notices of violation that have carried a penalty in 2020, 2021, 2022 and 2023 through the date of this prospectus. We have established a four-tiered emissions monitoring ecosystem through which we monitor our wells and facilities via satellite, fixed wing aircraft, continuous perimeter sensors (largely through our Project Canary partnership), and handheld Forward Looking Infrared (FLIR) cameras. We completed a self-audit of our environmental management system in the third quarter of 2022 for alignment to ISO 14001 (a set of environmental management standards). As of June 30, 2024, we have certified approximately 70% of our production in NEPA with Project Canary TrustWell and achieved a Gold rating for 135 evaluated wells; a strong rating that will enable us to sell RSG. In the Barnett, we have received TrustWell certification for 1,687 wells on 398 pads and have achieved Gold rating for these wells, totaling approximately 45% of our Barnett production. We expect to continue the TrustWell certification process throughout our NEPA and Barnett assets in the coming years.

As a top 20 gas-weighted natural gas producer in the U.S. market, we believe we have a significant opportunity to reduce our environmental footprint by reducing GHG emissions through a series of strategic projects and technological commitments, and by offsetting remaining operational emissions. We have set a goal of reaching net zero Scope 1 and 2 emissions across our owned and operated upstream and natural gas midstream businesses by the early 2030s. To achieve our net zero goals, we invested approximately $9.1 million and $4.5 million in 2022 and 2023, respectively, to reduce emissions from our operations. These investments allowed us to prototype and deploy electrified components into the production processes, convert pneumatic gas instruments through our "Pad of the Future" program, enhance measurement technology, remove redundant equipment and develop and draw on renewable energy sources, among other operational improvements.

We also aspire to offset 100% of the combined Scope 1, 2 and 3 emissions from our owned and operated upstream and natural gas midstream businesses by the late 2030s. We believe we have a path to these net-zero goals through the expansion of our carbon negative businesses, such as significant expansion of our CCUS activities and our ongoing BKV dCarbon Ventures efforts. We believe we can achieve these goals based on potential completion of the currently identified potential CCUS projects in our project pipeline upon agreeable terms that we believe are obtainable. In addition to the CCUS projects we have identified, we expect to continue to identify and evaluate additional CCUS projects.

Our CCUS business and all of our CCUS projects are in the early stages of development. Although we commenced commercial operations with the initial injection of CO_2 waste at the Barnett Zero Project in November 2023, and have reached FID and entered into definitive agreements with respect to the Cotton Cove Project, we have not reached FID with respect to or entered into the definitive agreements necessary to execute any of the other fifteen potential projects identified above and may not be able to reach agreement on terms acceptable to us, or to achieve our projected timeline for commercial operations. In addition, the development of our CCUS business is expected to require material capital investments, and the projected timeline for commercial operations depends on our ability to fund the anticipated capital requirements for the potential projects that we have identified through external funding and revenues from our upstream business. Furthermore, the commercial viability of our CCUS projects depends, in part, on obtaining necessary permits and other regulatory approvals and on our ability to receive our portion of the anticipated Section 45Q tax credits associated with these projects. In particular, we must meet certain wage and apprenticeship requirements in order to qualify for enhanced Section 45Q tax credits. For more information on our CCUS business, see "*— Overview — Our Operations — Carbon Capture, Utilization and Sequestration" and "— Our Operations — Carbon Capture, Utilization and Sequestration*." For more information about the risks involved in our CCUS business, see "*Risk Factors — Risks Related to Our CCUS Business*" Another way we are enabling CO_2 emission reduction from our operations is by increasing our production of RSG. As of June 30, 2024, we have certified approximately 70% of our NEPA production and approximately 45% of our Barnett production and, in each case, earned a Gold rating with Project Canary's TrustWell environmental assessment.

Human Capital Resources

As of June 30, 2024, we had a total of 356 employees, which includes employees added following the completion of the Exxon Barnett Acquisition. We hire independent contractors on an as needed basis. We believe we have good relations with our employees. We and our employees are not subject to any collective bargaining agreements.

Safety. Safety is our highest priority, including the prevention of any releases from our operations. We conduct routine maintenance and inspections at our facilities, and we have established practices and operational infrastructure to control and mitigate potential spills or discharges. We also offer annual specialized training to staff on spill prevention and host routine Response Tabletop Sessions to ensure our teams are fully trained on our response plan in the event of any releases. We believe these measures continue to strengthen our process safety culture.

Compensation and Benefits. We recognize that our employees are our most valuable resource and that we must provide competitive compensation to ensure we attract and retain top talent. As part of our commitment to these efforts, we underwent a third-party evaluation to confirm our compensation was both competitive and reflective of the work our employees were performing. We have standardized our job and pay structure based on best practices and market data. We continue to survey and update our pay structure to stay competitive with our peers. We have implemented a compensation framework that strives to pay employees fairly and consistently based on their skills, experience and performance and that we believe is competitive compared to other companies in our industry.

To foster the health and well-being of our employees and their families, we offer all of our full- and part-time employees access to financial, health and wellness programs. We also offer short-term and long-term incentive plans, medical insurance coverage, parental leave, and paid time off for holidays, personal days and vacation.

Diversity and Inclusion. We strongly believe that a diverse workforce fosters new ideas and makes us stronger as a company. Providing a safe, inclusive working environment for our employees and contractors is among our top priorities. Our executive leaders are committed sponsors and supporters of programs that foster an increase in diverse demographic representation, nurture the careers of underrepresented groups and create a greater sense of inclusion and belonging.

In 2021, we implemented a new code of business conduct, updating our employee policies and completing an employee handbook refresh. Among the policies that were updated was our whistleblower policy. In conjunction with the update of the whistleblower policy, we launched our confidential ethics and compliance hotline (in addition to our online submission portal).

In 2022, we implemented a comprehensive manager and employee online training program across the Company that includes topics such as business ethics, human rights and diversity, equity and inclusion and that will be tracked to ensure participation.

We are also prioritizing the formal buildout of employee resource groups to create more opportunity for colleagues and peers to connect with others facing similar situations or challenges.

Human Rights. Providing a safe, inclusive working environment for our employees and contractors is a priority. We do not tolerate discrimination or harassment of any kind. We also have a Human Rights Policy that applies to all of our employees and is aligned with the UN Declaration of Human Rights and the UN Guiding Principles on Business and Human Rights. We continue to monitor the effectiveness of our human rights policy with the goal of growing and aligning our business to the dynamic rights of our workforce. Our Human Rights Policy extends to all our operations, as well as partners and suppliers, including security providers.

Recruitment, Retention and Development. We provide equal opportunity for all employees and consultants regardless of race, religion, gender, sexual orientation, age, ethnic or national origin, social origin, disability, family status or any other protected status and personal characteristics for all aspects of employment. This applies to recruitment and talent attraction, training and professional development opportunities, promotions and all employee benefits. Additionally, we prioritize local hiring for both employees and contractors, particularly in areas of field operations, to support employment opportunities in our local communities.

Government Regulation and Environmental Matters

Our operations are subject to extensive federal, state and local laws and regulations that govern oil and natural gas operations, regulate the discharge of materials into the environment or otherwise relate to the protection of the environment. These laws, rules and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- require notice to stakeholders of proposed and ongoing operations;
- require the installation of expensive pollution control equipment;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and gas drilling and production and saltwater disposal activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, or otherwise restrict or prohibit activities that could impact the environment, including water resources; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to plug and abandon wells.

Numerous governmental departments issue rules and regulations to implement and enforce such laws that are often difficult and costly to comply with and which carry substantial administrative, civil and even criminal penalties, as well as the issuance of injunctions limiting or prohibiting our activities for failure to comply. Violations and liabilities with respect to these laws and regulations could also result in remedial clean-ups, natural resource damages, permit modifications or revocations, operational interruptions or shutdowns and other liabilities. The costs of remedying such conditions may be significant, and remediation obligations could adversely affect our financial condition, results of operations and cash flows. In certain instances, citizens or citizen groups also have the ability to bring legal proceedings against us if we are not in compliance with environmental laws or to challenge our ability to receive environmental permits that we need to operate. 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 and natural resource damages and cleanup costs without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and gas production below the rate that would otherwise exist or even prohibit exploration or production activities in sensitive areas. In addition, state laws often require some form of remedial action to prevent pollution from former operations, such as plugging of abandoned wells. As of June 30, 2024, we have recorded asset retirement obligations of $194.4 million attributable to these activities. The regulatory burden on the oil and gas industry increases its cost of doing business and consequently affects its profitability. These laws, rules and regulations affect our operations, as well as the oil and gas exploration and production industry in general.

We believe that we are in material compliance with current applicable environmental laws, rules and regulations and that continued compliance with existing requirements will not have a material impact on our financial condition, results of operations or cash flows. Nevertheless, changes in existing environmental laws or regulations or the adoption of new environmental laws or regulations, including any significant limitation on the use of hydraulic fracturing, could have the potential to adversely affect our financial condition, results of operations and cash flows. Federal, state or local administrative decisions, developments in the federal or state court systems or other governmental or judicial actions may influence the interpretation or enforcement of environmental laws and regulations and may thereby increase compliance costs. Environmental regulations have historically become more stringent over time, and thus, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation.

The following is a summary of the significant environmental laws to which our business operations are subject.

CERCLA. The Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, is also known as the “Superfund” law. CERCLA and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on parties that are considered to have contributed to the release of a “hazardous substance” into the environment. These persons include the current or former owner or operator of the site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Such “responsible parties” may be subject to joint and several liability under CERCLA for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We currently own or lease properties that have been used for the exploration and production of natural gas, NGLs and oil for a number of years. Although operating and disposal practices that were standard in the industry at the time may have been utilized, it is possible that hydrocarbons or other wastes may have been disposed of or released on or under the properties currently owned or leased by us. Many of these properties have been operated by third parties whose treatment or release of hydrocarbons or other wastes was not under our control. These properties, and any wastes that may have been released on them, may be subject to CERCLA, and we could potentially be required to investigate and remediate such properties, including soil or groundwater contamination by prior owners or operators, or to perform remedial plugging or pit closure operations to prevent future contamination. States also have environmental cleanup laws analogous to CERCLA, including Texas.

RCRA. The Resource Conservation and Recovery Act, or RCRA, and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the EPA, the individual states administer some or all of the provisions of RCRA. While there is currently an exclusion from RCRA for drilling fluids, produced waters and most of the other wastes associated with the exploration and production of oil or gas, it is possible that some of these wastes could be classified as hazardous waste in the future and therefore be subject to more stringent regulation under RCRA. For example, in December 2016, the EPA and certain environmental organizations entered into a consent decree to address the EPA’s alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production-related oil and gas wastes from regulation as hazardous wastes under RCRA. The consent decree required the EPA to propose a rulemaking no later than March 15, 2019, for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or to sign a determination that revision of the regulations is not necessary; the EPA ultimately determined that a revision was not necessary. Also, in the course of our operations, we generate some amounts of ordinary industrial wastes that may be regulated as hazardous wastes if such wastes have hazardous characteristics.

Oil Pollution Act. The Oil Pollution Act of 1990, or the OPA, contains numerous restrictions relating to the prevention of and response to oil spills into waters of the United States. The term “waters of the United States” has been interpreted broadly to include inland water bodies, including wetlands and intermittent streams. The OPA imposes certain duties and liabilities on certain “responsible parties” related to the prevention of oil spills and damages resulting from such spills in or threatening waters of the United States or adjoining shorelines. For example, operators of certain oil and gas facilities must develop, implement and maintain facility response plans, conduct annual spill training for certain employees and provide varying degrees of financial assurance. Owners or operators of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge is one type of “responsible party” who is liable. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs, and certain other damages arising from a spill. As such, a violation of the OPA has the potential to adversely affect our business, financial condition, results of operations and cash flows.

Clean Water Act. The CWA and implementing regulations, which are primarily executed through a system of permits, also govern the discharge of certain pollutants into waters of the United States. Enforcement for failure to comply strictly with the CWA are generally resolved by payment of fines and correction of any identified deficiencies. However, regulatory agencies could require us to cease construction or operation of certain facilities or to cease hauling wastewaters to facilities owned by others that are the source of water discharges to resolve non-compliance. The CWA also requires the preparation and implementation of Spill Prevention, Control and Countermeasure Plans in connection with on-site storage of significant quantities of oil. In 2016, the EPA finalized new wastewater pretreatment standards that would prohibit onshore unconventional oil and gas extraction facilities from sending wastewater to publicly-owned treatment works. This restriction of disposal options for hydraulic fracturing waste may result in increased costs. In addition, state laws analogous to the CWA also may require permits for certain of our operations.

Safe Drinking Water Act. The SDWA and comparable local and state provisions restrict the disposal, treatment or release of water produced or used during oil and gas development. Subsurface emplacement of fluids (including oil and gas wastewater disposal wells or enhanced oil recovery) is governed by U.S. federal or state regulatory authorities that, in some cases, includes the state oil and gas regulatory authority or the state's environmental authority. The SDWA's UIC Program requires that we obtain permits from the EPA or delegated state agencies for our disposal and other injection wells, establishes minimum standards for UIC well operations, restricts the types and quantities of fluids that may be injected and prohibits the migration of fluid containing any contaminants into underground sources of drinking water. Any leakage from the subsurface portions of the UIC wells may cause degradation of freshwater, potentially resulting in cancellation of operations of a well, imposition of fines and penalties from governmental agencies, incurrence of expenditures for remediation of affected resources, and imposition of liability by landowners or other parties claiming damages for alternative water supplies, property damages, and personal injuries. In addition, in some instances, the operation of UIC wells has been alleged to cause earthquakes (induced seismicity) as a result of flawed well design or operation. This has resulted in stricter regulatory requirements in some jurisdictions relating to the location and operation of UIC wells, and regulators in some states have imposed or are seeking to impose additional requirements, including requirements regarding the permitting of produced water disposal wells or otherwise, to assess the relationship between seismicity and the use of such wells. The adoption of federal, state and local legislation and regulations intended to address induced seismic activity in the areas in which we operate could restrict our drilling and production activities, as well as our ability to dispose of produced water gathered from such activities, which could result in increased costs and additional operating restrictions or delays.

We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with the wells in which we act as operator. Hydraulic fracturing is an important and commonly used process in the completion of oil and gas wells, particularly in unconventional plays, and is generally exempted from federal regulation as underground injection (unless diesel is a component of the fracturing fluid) under the SDWA. Concerns have been raised that hydraulic fracturing activities, separate and apart from use of UIC wells, may be correlated to induced seismicity. In addition, the EPA conducted a comprehensive study of the potential adverse impacts of hydraulic fracturing on drinking water and ground water and released its final report on this study in December 2016. The report found that hydraulic fracturing activities can impact drinking water resources under some circumstances, including large volume spills and inadequate mechanical integrity of wells. This study and other studies that may be undertaken by the EPA or other federal agencies could spur initiatives to further regulate hydraulic fracturing under the SDWA, the Toxic Substances Control Act, or other statutory and/or regulatory mechanisms, which could lead to operational delays, increased operating and compliance costs and additional regulatory burdens that could make it more difficult or commercially impracticable for us to perform hydraulic fracturing. Such costs and burdens could delay the development of unconventional gas resources from shale formations, which are not commercially feasible without the use of hydraulic fracturing.

Additionally, the EPA has established the Class VI well classification under the SDWA UIC for wells used for long-term geologic sequestration of CO_2. We will be required to obtain a Class VI permit for our CCUS projects that do not meet the criteria for Class II oil and gas related acid gas injection wells. The Class VI UIC permit program is currently administered by the EPA in all states except for Louisiana, Wyoming and North Dakota, which have assumed primacy for Class VI permitting. Class VI permits currently require a lengthy permitting process, and the costs and regulatory burdens associated with obtaining Class VI permits could delay development of our CCUS projects.

Chemical Disclosures Related to Hydraulic Fracturing. A number of states, including Texas, have implemented chemical disclosure requirements for hydraulic fracturing operations. We currently disclose all hydraulic fracturing additives we use on www.FracFocus.org, a website created by the Ground Water Protection Council and Interstate Oil and Gas Compact Commission.

Prohibitions and Other Regulatory Limitations on Hydraulic Fracturing. There have been a variety of regulatory initiatives at the state level to restrict oil and gas drilling operations in certain locations.

In addition to chemical disclosure rules, some states have implemented permitting, well construction or water withdrawal regulations that may increase the costs of hydraulic fracturing operations. For example, Texas has water withdrawal restrictions allowing suspension of withdrawal rights in times of shortages while other states require reporting on the amount of water used and its source.

Increased regulation of and attention given by environmental interest groups, as well as state and federal regulatory authorities, to the hydraulic fracturing process could lead to greater opposition to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and gas, including from developing shale plays, or could make it more difficult to perform hydraulic fracturing. These developments could also lead to litigation challenging proposed or existing wells. The adoption of federal, state or local laws or the implementation of regulations regarding hydraulic fracturing that are more stringent could cause a decrease in the completion of new oil and gas wells, as well as increased compliance costs and time, which could adversely affect our financial position, results of operations and cash flows. We use hydraulic fracturing extensively and any increased federal, state, or local regulation of hydraulic fracturing could reduce the volumes of oil and gas that we can economically recover.

Clean Air Act. Our operations are subject to the Clean Air Act, or the CAA, and comparable state and local requirements to control emissions from sources of air pollution. Federal and state laws require new and modified sources of air pollutants to obtain permits prior to commencing construction. Major sources of air pollutants are subject to more stringent, federally imposed requirements including additional permitting requirements. Federal and state laws designed to control toxic air pollutants and GHGs might require installation of additional controls. Payment of fines and correction of any identified deficiencies generally resolve any failures to comply strictly with air regulations or permits. However, in the event of non-compliance, regulatory agencies could also require us to cease construction or operation of certain facilities or to install additional controls on certain facilities that are air emission sources. Further, stricter requirements could negatively impact our production and operations.

In 2012, the EPA published final New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAPS, that amended the existing NSPS and NESHAP for the oil and natural gas sector. In June 2016, the EPA published a final rule that updated and expanded the NSPS by setting additional emissions limits for volatile organic compounds and regulating methane emissions for new and modified sources in the oil and gas industry. In June 2017, the EPA proposed a two-year stay of certain requirements contained in the June 2016 rule. In March 2018, the EPA published a final rule that amended two narrow provisions of the NSPS, removing the requirement for completion of delayed repair during emergency or unscheduled vent blowdowns. In September 2020, the EPA published a final rule amending the 2012 and 2016 NSPS for the oil and natural gas sector that removed transmission and storage sources from the oil and natural gas industry source category and rescinded the methane requirements applicable to the production and processing sources. On June 30, 2021, President Biden signed into law a joint Congressional resolution under the Congressional Review Act nullifying the September 2020 rule amending the EPA's 2012 and 2016 NSPS standards for the oil and natural gas sector and effectively reinstating the prior standards. More recently, on December 2, 2023, the EPA announced its finalized 2023 Methane Rules, which establish requirements for methane emissions from existing and modified oil and gas sources and imposed additional requirements for new sources with respect to methane emissions, including sourcing not previously regulated under the oil and gas source category. The reinstatement of direct regulation of methane emission for new sources, promulgation of requirements for existing oil and gas sources and enhanced requirements for new sources and the expansion of sources covered by the EPA's rules, could result in increased compliance costs or otherwise impact our results of operations. For additional information, see "*Risk Factors — Risks Related to Environmental, Legal Compliance and Regulatory Matters — Our operations are subject to a series of risks relating to climate change that could result in increased compliance or operating costs, limit the areas in which we may conduct natural gas and NGL exploration and production activities, and reduce demand for the natural gas and NGLs we produce.*"

In October 2015, the EPA revised the existing National Ambient Air Quality Standards for ground level ozone to make the standard more stringent. The EPA finished promulgating final area designations under the new standard in 2018, which, to the extent areas in which we operate have been classified as non-attainment, may result in an increase in costs for emission controls and requirements for additional monitoring and testing, as well as a more cumbersome permitting process. Generally, it will take the states several years to develop compliance plans for their non-attainment areas. In December 2020, the EPA completed its review of the currently available scientific evidence and risk information and decided to retain the existing ozone National Ambient Air Quality Standards. While we are not able to determine the extent to which this standard will impact our business at this time, it has the potential to have a material impact on our operations and cost structure.

In June 2016, the EPA finalized a rule "aggregating" individual wells and other facilities and their collective emissions for purposes of determining whether major source permitting requirements apply under the CAA. These changes may introduce uncertainty into the permitting process and could require more lengthy and costly permitting processes and more expensive emission controls.

Collectively, these rules and proposed rules, as well as any future laws and their implementing regulations, may require a number of modifications to our operations. We may, for example, be required to install new equipment to control emissions from our well sites or compressors at initial startup or by the applicable compliance deadline. We may also be required to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

Greenhouse Gas and Climate Change Laws and Regulations. Scientific studies have concluded that increasing concentrations of GHGs in the Earth's atmosphere are producing climate changes that have significant physical effects. Potential physical risks resulting from climate change may be event driven (including increased severity of extreme weather events, such as hurricanes, droughts, or floods) or longer-term shifts in climate patterns that may cause sea level rise or chronic heat waves. Potential physical risks may cause direct damage to our assets as well as indirect impacts such as supply chain disruption and also could include changes in water availability, sourcing, and quality, which could impact drilling and completion operations. These physical risks could cause increased costs, production disruptions, lower revenues and substantially increase the cost or limit the availability of insurance. In response to studies indicating that emissions of carbon dioxide and certain other GHGs, including methane, are contributing to global climate change, there is increasing focus by local, state, regional, national and international regulatory bodies as well as by investors and the public on GHG emissions and climate change issues.

While the United States has yet to adopt comprehensive climate change legislation, the federal government has taken a series of administrative actions aimed at curtailing GHG emissions. For example, in response to 2009 findings that emissions of CO_2, methane and other GHGs present an endangerment to public health and the environment, the EPA issued regulations to restrict emissions of GHGs under existing provisions of the CAA. These regulations include limits on tailpipe emissions from motor vehicles and preconstruction and operating permit requirements for certain large stationary sources.

In August 2015, the EPA promulgated the Clean Power Plan ("CPP") rule to limit CO_2 emissions from existing coal and natural-gas fired electric generating units. The CPP rule, which never went into effect, adopted a sector-wide, generation shifting approach and determined the best system of emissions reduction (BSER) for CO_2 at coal and natural-gas fired units included three components — heat rate improvement at existing coal-fired units, a shift in generation from coal-fired to natural-gas fired units, and a shift in generation from natural-gas fired facilities to renewables. Several industry groups and states challenged the CPP rule. On February 9, 2016, the U.S. Supreme Court stayed the implementation of the CPP rule pending judicial review. In August 2019, the EPA repealed the CPP rule and replaced it with the Affordable Clean Energy rule, or ACE rule, which adopted a narrower, source-based approach limited to designating heat rate improvement, or efficiency improvement, as the BSER for CO_2 from existing coal-fired electric generating units. The ACE rule and the repeal of the CPP rule were challenged by several states and private parties. On January 19, 2021, the D.C. Circuit vacated the ACE rule but at the EPA's request subsequently stayed issuance of the portion of the mandate that would have vacated the repeal of the CPP rule while the EPA decided whether it would promulgate a new rule instead of the CPP rule. On October 29, 2021, the U.S. Supreme Court agreed to review the D.C. Circuit's decision, and on June 30, 2022 the U.S. Supreme Court ruled that the generation-shifting approach included in the CPP rule exceeded the EPA's statutory authority under the CAA. Additionally, on May 11, 2023, the EPA announced proposed limits on GHG emissions from existing coal and new natural-gas electric generating units, which could compel such facilities to install additional pollution controls. The EPA finalized this rule in May 2024, which sets NSPS for new and modified coal- and gas-fired plants and emission guidelines for existing coal-fired plants, representing the first time the federal government has attempted to restrict CO_2 emissions from existing electric generating units. However, whether and how such rules would affect our business is uncertain.

The EPA has issued the "Final Mandatory Reporting of Greenhouse Gases" Rule and a series of revisions to it, which requires operators of oil and gas production, natural gas processing, transmission, distribution and storage facilities and other stationary sources emitting more than established annual thresholds of carbon dioxide-equivalent GHGs to inventory and report annually their GHG emissions occurring in the prior calendar year on a facility-by-facility basis. The EPA widened the scope of annual GHG reporting to include not only activities associated with completion and workover of gas wells with hydraulic fracturing and activities associated with oil and gas production operations, but also completions and workovers of oil wells with hydraulic fracturing, gathering and boosting systems, and transmission pipelines. These rules do not require control of GHGs. However, the EPA has indicated that it will use data collected through the reporting rules to decide whether to promulgate future GHG limits. More recently, on December 2, 2023, the EPA announced its finalized 2023 Methane Rules, which establish requirements for methane emissions from existing and modified oil and gas sources and imposed additional requirements for new sources with respect to methane emissions, including sourcing not previously regulated under the oil and gas source category. For more information, see "*Risk Factors — Risks Related to Environmental, Legal Compliance and Regulatory Matters — Our operations are subject to a series of risks relating to climate change that could result in increased compliance or operating costs, limit the areas in which we may conduct natural gas and NGL exploration and production activities, and reduce demand for the natural gas and NGLs we produce*."

In certain circumstances, large sources of GHG emissions are subject to preconstruction permitting under the EPA's Prevention of Significant Deterioration program. This program historically has had minimal applicability to the oil and gas production industry. However, there can be no assurance that our operations will avoid applicability of these or similar permitting requirements, which impose costs relating to emissions control systems and the efforts needed to obtain the permit.

In April 2016, the United States signed the Paris Agreement, which requires countries to review and "represent a progression" in their intended nationally determined contributions ("NDC"), which set GHG emission reduction goals, every five years beginning in 2020. In November 2019, the Trump Administration formally moved to exit the Paris Agreement, initiating the treaty-mandated one-year process at the end of which the United States officially exited the agreement. However, the current Presidential administration has made climate change a central priority and on January 20, 2021, his first day in office, President Biden announced its intention to rejoin the Paris Agreement. The United States officially rejoined the Paris Agreement on February 19, 2021, and in April 2021 submitted its NDC. The United States NDC sets an economy-wide target of net GHG emissions reduction from 2005 levels of 50-52% by 2030. The specific measures to be taken in furtherance of achieving this target have not been established, but the NDC submission indicated that an interagency approach will play an important role, including regulatory, technology and policy initiatives designed to reduce the generation of GHG emissions and to incentivize the capture and geologic sequestration or utilization of carbon dioxide that would otherwise be emitted in the atmosphere. Also on his first day in office, President Biden signed an executive order on climate action and reconvened an interagency working group to establish interim and final social costs of three GHGs: carbon dioxide, nitrous oxide, and methane. Carbon dioxide is released during the combustion of fossil fuels, including natural gas, NGLs and oil, and methane is a primary component of natural gas. The Biden Administration stated it will use updated social cost figures to inform federal regulations and major agency actions and to justify aggressive climate action as the United States moves toward a "100% clean energy" economy with net-zero GHG emissions.

The United States Congress has also passed a number of bills in recent years aimed at addressing climate change in a limited manner, primarily directed at funding climate change initiatives. The 2021 Infrastructure and Investment Jobs Act passed by Congress in November 2021 included measures aimed at decarbonization to address climate change, including funding for replacing transit vehicles, including buses, with zero- and low-emission vehicles and for the deployment of an electric vehicle charging network nationwide. This legislation, and other future laws, that promote a shift toward electric vehicles could adversely affect the demand for our products. Similarly, the Inflation Reduction Act, recently passed by Congress, imposed several new climate-related requirements on oil and gas operations. Moreover, in August 2022, Congress passed, and President Biden signed into law, the Inflation Reduction Act of 2022, which appropriates significant federal funding for renewable energy initiatives and, for the first time ever, imposes a fee on GHG emissions from certain facilities. The emissions fee and funding provisions of the law could increase our operating costs and accelerate the transition away from fossil fuels, which could in turn adversely affect our business and results of operations.

In the absence of comprehensive climate change legislation at the federal level, a number of state and regional efforts have emerged. These include measures aimed at tracking and/or reducing GHG emissions through cap-and-trade programs, which typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting GHGs. In addition, a coalition of over 20 governors of U.S. states formed the United States Climate Alliance to advance the objectives of the Paris Agreement, and several U.S. cities have committed to advance the objectives of the Paris Agreement at the state or local level as well. To this end, the California governor issued an executive order on September 23, 2020 ordering actions to pursue GHG emissions reductions, including a direction to the California State Air Resources Board to develop and propose regulations to require increasing volumes of new zero-emission passenger vehicles and trucks sold in California over time, with a targeted ban of the sale of new gasoline vehicles by 2035.

If we are unable to recover or pass through a significant portion of our costs related to complying with current and future regulations relating to climate change and GHGs, it could materially affect our operations and financial condition. Any future laws or regulations that limit emissions of GHGs from our equipment and operations could require us to both develop and implement new practices aimed at reducing GHG emissions, such as emissions control technologies, which could increase our operating costs and could adversely affect demand for the oil and gas that we produce. 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. Future implementation or adoption of legislation or regulations adopted to address climate change could also make our products more or less desirable than competing sources of energy. At this time, it is not possible to quantify the impact of any such future developments on our business.

OSHA. We are subject to the requirements of the Occupational Safety and Health Act, or OSHA, and comparable state laws that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations, and the provision of such information to employees, state and local government authorities and citizens. Other OSHA standards regulate specific worker safety aspects of our operations.

Endangered Species Act. The ESA was established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. The U.S. Fish and Wildlife Service may designate critical habitat and suitable habitat areas it believes are necessary for survival of a threatened or endangered species. While some of our facilities are in areas that may be designated as a habitat for endangered species, we believe that we are in substantial compliance with the ESA. The presence of any protected species or the final designation of previously unprotected species as threatened or endangered in areas where we operate could result in increased costs from species protection measures or could result in limitations, delays, or prohibitions on our exploration and production activities that could have an adverse effect on our ability to develop and produce our reserves.

National Environmental Policy Act. Oil and gas exploration and production activities on federal lands trigger review under the National Environmental Policy Act. The National Environmental Policy Act requires federal agencies, including the U.S. Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment of the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. This process has the potential to delay or even halt development of some of our oil and gas projects.

Environmental Justice Considerations. Recent attention to environmental justice considerations — from both government regulators and activist groups — may impede or otherwise have an adverse effect on our ability to develop both our fossil fuel assets and our proposed CCUS projects. In particular, on April 21, 2023, President Biden signed a new executive order focused on incorporating environmental justice considerations into federal decision-making. The executive order created a new White House Office of Environmental Justice, and directed all federal agencies to make environmental justice a central part of each agency's mission by publishing an environmental justice strategic plan for the agency. Additionally, the order requires agencies conducting National Environmental Policy Act reviews to assess direct, indirect and cumulative impacts on environmental justice communities in their analyses, to consider best available science and information on disparate health impacts related to exposure to environmental hazards and provide opportunities for meaningful engagement with environmental justice communities during the environmental review process. It remains to be seen how federal agencies will undertake to comply with these new requirements addressing environmental justice considerations, but the development and application of the new requirements may result in permit uncertainty and delays for our activities that require federal approvals.

Operating Hazards and Insurance

Natural gas, NGLs and oil operations are subject to many risks, including well blowouts, craterings, explosions, uncontrollable flows of oil, natural gas or well fluids, fires, pipe, casing or cement failures, abnormal pressure, pipeline leaks, ruptures or spills, vandalism, pollution, releases of toxic gases, adverse weather conditions or natural disasters and other environmental hazards and risks.

In accordance with what we believe to be industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. We cannot provide assurance that any insurance we obtain will be adequate to cover our losses or liabilities. We have elected to self-insure for certain items for which we have determined that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

The insurance policies we currently maintain, and their respective policy limits, are as follows:

- *Commercial General Liability*: $2,000,000 annual general aggregate policy limit or $1,000,00 per occurrence.
- *Property*: annual aggregate policy limits of $1,840,585 for personal property and $50,000 to $3,200,000 for certain real property.
- *Operators Extra Expense (Limits assume 100% working interest and scale accordingly)*:
  - $25,000,000 per occurrence limit for wells located in Pennsylvania;
  - $20,000,000 per occurrence limit for wells located in Pennsylvania spud prior to 2013;
  - $15,000,000 per occurrence limit for wells located in Texas;
  - $30,000,000 per occurrence additional limit for property under our care, custody or control; and
  - $2,500,000 per occurrence additional limit for certain materials and supplies.
- *Oil Lease Property (Limits assume 100% working interest and scale accordingly)*: $378,238,108 annual aggregate policy limit for physical loss and/or physical damage to certain scheduled onshore property.

- *Business and Contingent Business Interruption*: $64,240,000 annual aggregate limit per accident or occurrence, or $176,000 per day on our most significant facilities with lower limits on other locations.
    - $64,200,000 Combined Single Limit for Contingent Business Interruption relating to Bridgeport, TX facility subject to $176,000 Maximum Daily Values and 365 Day Maximum Recover Period;
    - $13,376,000 Combined Single Limit for Direct Business Interruption subject to $74,313 Maximum Daily Values and 180 Day Maximum Recover Period Per Schedule (PA); and
    - $7,912,000 Combined Single Limit for Direct Business Interruption subject to $87,912 Maximum Daily Values and 90 Day Maximum Recover Period Per Schedule (TX).
- *Site Pollution Incident Legal Liability*: $11,000,000 annual aggregate policy limit, with a $10,000,000 limit per incident.
- *Management Liability*:
    - $5,000,000 annual aggregate policy limit for director, officer and organizational liability, with an additional $1,000,000 of coverage for claims against certain insured persons;
    - $2,000,000 annual aggregate policy limit for employment practices liability;
    - $1,000,000 aggregate policy limit for fiduciary liability; and
    - $1,000,000 for certain crime liability.
- *Automobile Liability*: $1,000,000 aggregate policy limit.
- *Workers' Compensation*: limited to the value of the benefits required under Colorado, Montana, Oregon, Pennsylvania or Texas law, as applicable.
- *Employer's Liability*: $1,000,000 limit per accident for bodily injury by accident, and $1,000,000 aggregate policy limit for bodily injury by disease.
- *Umbrella Excess Liability*: $75,000,000 per occurrence and aggregate policy limit covering damages in excess of policy limits for commercial general liability, automobile liability, employee benefits liability and employer's liability.
- *Cybersecurity and Identity Fraud Liability*: $10,000,000 aggregate policy limit for cyber and privacy liability.
- *Kidnap and Ransom*: $10,000,000 limit per insured event.

For more information about potential risks that could affect us, see "*Risk Factors — Risks Related to Our Business Generally — Our business is subject to operating hazards that could result in substantial losses or liabilities for which we may not have adequate insurance coverage*."

Other Facilities

Our corporate headquarters are located at 1200 17th Street, Suite 2100, Denver, Colorado 80202, and our telephone number at such address is (720) 375-9680. Our corporate headquarters are leased and our field office facilities are owned, and we believe that they are adequate for our current needs.

Title to Properties

Title to our oil and gas properties is subject to royalty, overriding royalty, carried, net profits, working, and similar interests customary in the oil and gas industry. Our properties may also be subject to liens incident to operating agreements, as well as other customary encumbrances, easements, and restrictions, and for current taxes not yet due. Our general practice is to conduct title examinations on material property acquisitions. Prior to the commencement of drilling operations, a title examination and, if necessary, curative work is performed. The methods of title examination that we have adopted are reasonable in the opinion of management and are designed to ensure that production from our properties, if obtained, will be salable by us. We believe that title to our oil and natural gas properties is good and defensible, subject only to such exceptions that we believe do not materially interfere with the use of such properties.

Legal Proceedings

From time to time, we may be subject to various claims, title matters and legal proceedings arising in the ordinary course of business, including environmental contamination claims, personal injury and property damage claims, claims related to joint interest billings and other matters under natural gas operating agreements and other contractual disputes. While the outcome and impact on the Company cannot be predicted with certainty, we believe that our ultimate liability with respect to any such matters will not have a significant impact or material adverse effect on our financial positions, results of operations or cash flows. Our results of operations and cash flows, however, could be significantly impacted in the reporting periods in which such matters are resolved.

MANAGEMENT

Directors and Executive Officers

The following table provides information regarding the individuals who are expected to constitute our executive officers and directors upon completion of this offering. Executive officers serve at the discretion of our board of directors and until their successors are elected and qualified. Messrs. C. Vongkusolkit and S. Vongkusolkit are father and son, respectively.

Name	Age	Current Position(s) with the Company
Christopher P. Kalnin	46	Chief Executive Officer and Director
John T. Jimenez	55	Chief Financial Officer
Eric S. Jacobsen	54	Chief Operating Officer
Barry S. Turcotte	54	Chief Accounting Officer
Lindsay B. Larrick	41	Chief Legal Officer
Ethan Ngo	42	Chief Technical Resources Officer
Mary Rita Valois	63	Chief Information Officer
Chanin Vongkusolkit	70	Chairman of the Board
Somruedee Chaimongkol	62	Director
Joseph R. Davis	74	Director
Akaraphong Dayananda	65	Director
Kirana Limpaphayom	49	Director
Carla S. Mashinski	61	Director
Thiti Mekavichai	62	Director
Charles C. Miller III	72	Director
Sunit S. Patel	62	Director
Anon Sirisaengtaksin	71	Director
Sinon Vongkusolkit	34	Director

Christopher P. Kalnin has served as Chief Executive Officer and a director of the Company since its formation in May 2020 and founded the Company in 2015. In September 2023, he was appointed as a member of a newly established Executive Committee of Banpu, with the delegation of authority to manage all aspects of Banpu's businesses in North America, among other things. He also worked at Kalnin Ventures, the fund manager of BKV O&G, owned by Banpu (SET: BANPU), as Managing Director from June 2014 to May 2020 and Group CEO from January 2019 to May 2020. Prior to that, Mr. Kalnin served in multiple roles at Level 3 Communications, Inc. ("Level 3 Communications"), a global provider of high-capacity communications services to businesses, serving as Vice President of Strategic Business Operations and Planning from January 2014 to June 2014 and Senior Director from February 2012 to December 2013. From January 2010 to July 2011, he served as a Strategy Advisor and Chief of Staff to the Chief Executive Officer at PTT Exploration (SET: PTTEP), a petroleum exploration and production company based in Thailand. Additionally, he served as Engagement Manager at McKinsey & Company, a management consulting firm, from October 2005 to January 2010 and Senior Analyst at Credit Suisse First Boston, the investment banking division of Credit Suisse Group, from July 2000 to July 2003. Mr. Kalnin received an HBA in Finance from the University of Western Ontario and an MBA from Northwestern University's Kellogg School of Management. We believe that Mr. Kalnin's extensive industry experience and demonstrated leadership capabilities throughout our growth make him qualified to serve on our board of directors.

John T. Jimenez has served as Chief Financial Officer of the Company since April 2021. Prior to joining the Company, he served as Chief Financial Officer of BP Gas and Power Trading Americas and a member of the board of directors of BP Energy Company, a subsidiary of BP (NYSE: BP), from January 2019 to April 2021. Mr. Jimenez also served as interim Chief Executive Officer and a member of the board of directors of VAKT Global Ltd, a venture established by some of the world's leading energy majors, trading houses and banks to develop a blockchain-based digital platform for post-transaction management of physical energy commodities, from January 2018 to December 2018 and Chairman of the board of directors of VAKT Holdings Ltd from January 2019 to April 2021. Prior to that, he served in various positions at various affiliates of BP, including, most recently, Vice President and Head of IST Global Finance Services from January 2016 to December 2017, Transformation Director from March 2014 to December 2015, Chief of Staff and Vice President of HR Strategy and Planning from May 2012 to March 2014 and Finance Director — Group HR from January 2006 to April 2012. In addition, he has held various leadership roles in international business environments, ranging from start-up operations to corporate head offices, in the US, UK, Mexico, Poland, Bulgaria and India. He has led a range of commercial activities, including large scale transformations, systems implementations, business turnarounds, business start-ups, analytics, strategy and business development. Mr. Jimenez received a BA in Accounting from Saint Mary’s University of Minnesota and an MBA from Northwestern University’s Kellogg School of Management.

Eric S. Jacobsen has served as Chief Operating Officer of the Company since its formation in May 2020. He also served as Chief Operating Officer of Kalnin Ventures from February 2020 to May 2020. Prior to that, he served as Senior Vice President of Extraction Oil & Gas, Inc. (previously NASDAQ: XOG), an independent oil and gas company focused on the acquisition, development and production of oil, natural gas and NGL reserves, from October 2016 to December 2019 and Director of Planning and Development, Director of Exploration and Production and Well Engineering Manager of Noble Energy, Inc. (previously NASDAQ: NBL), an independent energy company engaged in worldwide crude oil and natural gas exploration and production, where he led large-scale shale development efforts of the DJ Basin in Colorado, from January 2011 to October 2016. From June 1993 to January 2011, Mr. Jacobsen worked at BP (NYSE: BP) and its heritage companies, Atlantic Richfield Company and Vastar Resources, Inc., in Montana, Texas, Louisiana, Gulf of Mexico, Algeria, Azerbaijan and other locations and in various positions, including Operations Manager, Offshore Installation Manager and Reservoir Engineer. Mr. Jacobsen received a BS in Environmental Engineering and an MS in Petroleum Engineering from Montana Tech University.

Barry S. Turcotte has served as Chief Accounting Officer of the Company since December 2022. Prior to joining the Company, he most recently served as Senior Vice President and Chief Financial Officer of Crestone Peak Resources, a privately held oil and natural gas company, from May 2017 to November 2021. In addition, Mr. Turcotte served as Chief Accounting Officer of RSP Permian, Inc. (NYSE: RSPP), a publicly listed oil and natural gas company, from April 2014 to May 2017. Prior to that, he served in various positions at Swift Energy Company (NYSE: SFY), a publicly listed oil and natural gas exploration and production company, including Vice President of Accounting and Controller from December 2009 to April 2014, Assistant Controller from April 2005 to November 2009 and other progressive positions of responsibility after joining Swift Energy Company in 2001. He also served in various progressive accounting positions at Westlake Group of Companies, a global chemical manufacturer, from 1995 to 2001. Mr. Turcotte began his career as an auditor in the energy group of Ernst & Young LLP from 1993 to 1995. He has over 30 years of experience in the accounting and finance professions, including in the oil and gas industry. Mr. Turcotte is a Certified Public Accountant and received a BBA from the University of Houston and an Executive MBA from the University of Houston.

Lindsay B. Larrick has served as Chief Legal Officer of the Company since July 2022 and as Vice President, General Counsel and Corporate Secretary of the Company since its formation in May 2020. She also served as Vice President and General Counsel of Kalnin Ventures from October 2018 to May 2020. Prior to that, she was a partner at national law firms Fox Rothschild LLP from July 2016 to October 2018 and Lathrop & Gage LLP from January 2007 to July 2016. During her time at such law firms, she specialized in the energy practice, served in various management positions, including Chair of the Energy Practice Group for both firms, and gained experience in structuring private equity funds and mergers, acquisitions and divestitures in the oil and gas industry. Ms. Larrick received a BS in Business Administration and a JD from the University of Denver.

Ethan Ngo has served as Chief Technical Resources Officer of the Company since July 2022 and, prior to that, as Senior Vice President, Engineering of the Company since its formation in May 2020. He served at Kalnin Ventures as Senior Vice President, Engineering since December 2017 and Vice President, Engineering from March 2015 to December 2017. Prior to that, Mr. Ngo served as A&D Reservoir Engineer of Fidelity Exploration and Production Company, which is involved in the acquisition, exploration, development and production of natural gas and oil resources, from July 2014 to March 2015, Reservoir Engineer of Liberty Resources LLC, a Denver-based private equity backed oil and gas company, from April 2013 to June 2014 and Reservoir Engineer of Newfield Exploration Company (previously NYSE: NFX), an independent energy company, from April 2011 to April 2013. He also served as Senior Reservoir Engineer of ExxonMobil Production Company from February 2008 to March 2011. Mr. Ngo received a BS in Civil Engineering, an MS in International Political Economy and an ME in Petroleum Engineering from the Colorado School of Mines. Mr. Ngo also received an MBA from the University of Colorado, Denver.

Mary Rita Valois has served as Chief Information Officer of the Company since October 2023 and, prior to that, as Vice President of Information Technology of the Company since March 2023. Ms. Valois has also served as a director of Dana's Organic Wines, Inc. d/b/a Wander + Ivy, an early-stage, single-serve, premium organic wine business, since April 2022, and as a director of Spirit Free Beverages Co. d/b/a Gruvi, an early-stage non-alcoholic beer and wine business, since November 2021. Prior to joining the Company, Ms. Valois leveraged her extensive information technology experience to provide strategic guidance related to the technology and technology services sectors while serving as Senior M&A Advisor to CIVC Partners L.P., a Chicago-based private equity firm, from May 2020 to March 2023. Ms. Valois also served as Head of IT — North America for Abbott Nutrition, the nutrition productions division of Abbott Laboratories (NYSE: ABT), a multinational medical devices and health care company, from November 2021 to April 2022, during which time Ms. Valois was responsible digital and commercial solutions for all Abbott Nutrition brands in North America, and as U.S. M&A and IT Consulting Practice Leader and Executive Director of Ernst & Young LLP, from March 2015 to November 2017. Ms. Valois served as Global Chief Information Officer of Treasury Wine Estates Ltd (ASX: TWE), the former wine division of international brewing company Foster's Group Pty. Ltd, from December 2011 to June 2013, after serving as the company's Vice President — IT and Business Process Transformation, from August 2010 to December 2011. She also holds the title of Retired Partner at Deloitte & Touche LLP, where she provided IT consulting services as a Senior Manager from May 1995 to June 1996 and then as a Principal (Equity Partner) from June 1996 to August 2010. Ms. Valois received a BBA in Accounting from the University of Notre Dame and an MBA in Operations Management and Management Information and Decision Systems from Case Western Reserve University.

Chanin Vongkusolkit has served as Chairman of the Board of the Company since May 2020. He founded Banpu (SET: BANPU) in 1983 and has served as its Chairman of the Board since April 2016. His other positions at Banpu include director and Senior Executive Officer from 2015 to 2016 and director and Chief Executive Officer from 1983 to 2015. In addition, Mr. Vongkusolkit has served as a director of The Erawan Group Public Company Limited (SET: ERW), a hotel investor, developer and operator, since November 2004, and Chairman of its board of directors since April 2018. He has also served as a director of Mitr Phol Sugar Corp., Ltd., a sugar and bio-energy producer, since 1983 and various subsidiaries of Banpu, including Banpu Power (SET: BPP). Additionally, Mr. Vongkusolkit serves as Chairman of the Thai Listed Companies Association and an advisor at the Thammasat Economics Association. He previously served as a Commissioner at the Securities and Exchange Commission of Thailand from 2016 to 2018 and a director of Ratchaburi Electricity Generating Holding Public Company Limited, an independent power producer, from November 2003 to March 2011. Mr. Vongkusolkit received a Bachelor in Economics from Thammasat University and an MBA in Finance from St. Louis University. Mr. Vongkusolkit brings broad expertise in corporate development and leadership to the board of directors. In addition, we believe that Mr. Vongkusolkit's extensive experience with international energy companies makes him qualified to serve on our board of directors.

Somruedee Chaimongkol has served as a director of the Company since May 2020. She has served as a director of BNAC since February 2015. She previously served as the Chief Executive Officer and as a director of Banpu from April 2015 until March 2024, and prior to that served as the company's Chief Financial Officer from 2006 to 2015 and Senior Vice President of Finance from 2001 to 2006. In addition, Ms. Chaimongkol has served as a director of various subsidiaries of Banpu, including Banpu Power (SET: BPP). She has also served as a commissioner of PT. Indo Tambangraya Megah Tbk (IDX: ITMG), an Indonesian coal supplier, since March 2022, and served as a director of Biofuel Development Holdings Co., Ltd., from November 2010 to December 2018. Ms. Chaimongkol received a Bachelor's degree in Accounting from Bangkok University. Ms. Chaimongkol brings broad expertise in corporate leadership and financial matters to the board of directors. In addition, we believe that Ms. Chaimongkol's extensive experience as an executive and director at international energy companies makes her qualified to serve on our board of directors.

Joseph R. Davis has served as a director of the Company since May 2020. He has served as a director of Reconnaissance Energy Africa Ltd. d/b/a ReconAfrica (TSXV: RECO), a Canadian oil and gas company engaged in the exploration and development of oil and gas in Mexico, Namibia and Botswana, since January 2022. In 2014, Mr. Davis began working with our Chief Executive Officer, Chris Kalnin, as a consultant, and upon the formation of BKV O&G in June 2015, he assumed the role of Vice President of Geosciences with Kalnin Ventures. He was later promoted to Senior Vice President of Kalnin Ventures, and in January 2019, he became Chief Operating Officer and served in that position until his retirement in March 2020. In addition, he served as Exploration Advisor for Digital Prospectors, LLC, an exploration consulting firm, from May 2009 to May 2015 and Vice President of Hyperion Oil Iraq, L.L.C., an international oil and gas exploration company involved in Iraq and Latin America, from August 2006 to May 2009. From 1992 to 2006, he had a consulting business specializing in evaluation of oil and gas exploration projects. Mr. Davis received an AB in Earth Science from Dartmouth College, an MS in Geology from Southern Methodist University and a PhD in Geology from the University of Texas at Austin. Mr. Davis brings broad expertise in strategic planning and operations. In addition, we believe that Mr. Davis's upstream industry experience and executive experience make him qualified to serve on our board of directors.

Akaraphong Dayananda has served as a director of the Company since May 2020. He has served as a director and President of BNAC since February 2015. Prior to that, Mr. Dayananda served in various positions at Banpu (SET: BANPU) and Banpu Power (SET: BPP), including a director of Banpu Power from July 2009 to December 2017, Chief Strategy Officer — Head of Strategy and Business Development of Banpu from 2011 to 2019, Senior Vice President — Head of Strategy and Business Development of Banpu from 2006 to 2011, Senior Vice President — Head of Corporate Strategic Planning of Banpu from 1999 to 2006 and Senior Vice President — Finance of Banpu Power from 1997 to 1999. Prior to that, he gained expertise in the financial service sector while serving as Managing Director of Peregrine Nithi Finance and Securities Company Limited from 1995 to 1997 and in various positions at Thai Investment and Securities Plc from 1984 to 1995, including most recently Senior Vice President of Corporate Lending and Marketing. Mr. Dayananda has also served as a director of various subsidiaries of Banpu, both internationally and domestically throughout his career. Mr. Dayananda received a BS in Engineering from Chulalongkorn University and an MBA from Bowling Green State University. He also received certificates in various management and directorship programs, such as the Executive Program in Strategy and Organization from Stanford University and the Director Certificate Program from the Thai Institute of Directors. Mr. Dayananda brings broad expertise in strategic planning, business development and risk management to the board of directors. In addition, we believe that Mr. Dayananda's extensive experience as an executive and director and financial and investment experience make him qualified to serve on our board of directors.

Kirana Limpaphayom has served as a director of the Company since September 2023. He has served as Chief Operating Officer of Banpu (SET: BANPU) since April 2024, as Chief Executive Officer of Banpu Power (SET: BPP) since April 2020, as Executive Manager of Banpu Power Trading G.K., a licensed electricity retailer in Japan, since April 2021 and as Commissioner to PT. Indo Tambangraya Megah Tbk (IDX: ITMG), an Indonesian coal supplier, since March 2022. In September 2023, he was appointed as a member of a newly established Executive Committee of Banpu, with the delegation of authority to manage many aspects of Banpu's businesses in Asia, among other things. Mr. Limpaphayom also currently serves as a director of various subsidiaries of Banpu, including as a director of BKV-BPP Retail since July 2022, BPPUS and the BKV-BPP Power Joint Venture since July 2021 and Banpu Power since April 2020. He has also served as an Alternate Director of Centennial Coal Co. Pty Ltd. (ASX: CEY), an Australian mining company, since April 2014. Mr. Limpaphayom previously served as Head of Power at Banpu from April 2020 to April 2024, and as a President Director of PT. Indo Tambangraya Megah Tbk from March 2016 to May 2020. Prior to that, Mr. Limpaphayom served in various positions at Banpu and its subsidiaries, including as Head of Strategic Planning at Banpu from August 2009 until May 2013, as Executive Director of Banpu Australia Co. Pty. Ltd. from June 2013 until December 2015 and as President Director of PT. Indominco Mandiri, a subsidiary of PT. Indo Tambangraya Megah Tbk, from April 2016 until August 2017. Mr. Limpaphayom received a Bachelor of Economics and an MBA from the Chulalongkorn University, a Master of Science in Industrial Relations from the University of London and a PhD in Sociology from the

University of Warwick. Mr. Limpaphayom brings broad expertise in corporate leadership and financial matters to the board of directors. In addition, we believe that Mr. Limpaphayom's extensive experience as an executive and director at international energy companies makes him qualified to serve on our board of directors.

Carla S. Mashinski has served as a director of the Company since September 2022. Since 2019, she has served on the board of directors of Primoris Services Corporation (NYSE: PRIM), a specialty construction and infrastructure company in the United States, and has served as chair of its audit committee and a member of its compensation committee since 2021. She has also served on the board of directors and audit committee chair of Ranger Energy Services (NYSE: RNGR) since January 2024. Ms. Mashinski served as Chief Financial Officer of Cameron LNG, a liquefied natural gas terminal near the Gulf of Mexico, from 2015 to 2017, then was promoted to Chief Financial Officer and Administrative Officer and served in this role until her retirement in May 2022. Prior to that, she served as Chief Financial Officer and Vice President, Finance and Information Management, North American Operations, of Sasol Ltd. (JSE: SOL), an integrated energy and chemical company based in South Africa, from 2014 to 2015, Vice President, Finance and Administration and U.S. Chief Financial Officer of SBM Offshore (AMX: SBMO), a Dutch-based global group of companies servicing the offshore oil and gas industry, from 2008 to 2014 and Vice President, Accounting and Chief Accounting Officer/Controller of GulfMark Offshore, Inc., a global provider of marine transportation services, from 2004 to 2008. Her previous board experience includes serving as a director, and a member of the audit, compensation and nominating committees, of Carbo Ceramics Inc., a technology and services company servicing the oil and gas industry, from 2019 to 2020 and a director, and chair of the compensation committee and member of the audit committee, of Unit Corporation (OTC: UNTC), a diversified energy company, from 2015 to 2020. Since July 2022, she has also served on the board of directors of Lean In Energy, a non-profit organization that provides mentoring and professional development programs to women, particularly those working in the energy industry. Ms. Mashinski received a BS in Accounting with high honors from the University of Tennessee at Knoxville and an Executive MBA from the University of Texas at Dallas. She is a Certified Public Accountant in the State of Texas, Certified Management Accountant, Project Management Professional, National Association of Corporate Directors (NACD) Directorship Certified and holds a CERT Certification in Cybersecurity Oversight issued by the Software Engineering Institute of Carnegie Mellon University. Ms. Mashinski brings broad experience in financial and accounting matters and corporate governance to the board of directors. In addition, we believe that Ms. Mashinski's financial and accounting experience, U.S. public company board experience and upstream industry experience make her qualified to serve on our board of directors.

Thiti Mekavichai has served as a director of the Company since May 2020. He has served as Group Senior Vice President and Head of Oil and Gas of Banpu (SET: BANPU) since October 2023. He served as Chief Executive Officer of BNAC between January 2019 and September 2023. He has served as a director of BNAC since January 2019 and Head of Oil and Gas Business of Banpu (SET: BANPU) since November 2018. Prior to that, Mr. Mekavichai served as Executive Vice President of Human Resources and Business Services of PTT Exploration (SET: PTTEP) from October 2011 to September 2018 and Executive Vice President of Human Resources of Central Retail Corporation, Thailand's leading multi-format and multi-category retailing platform, from June 2008 to October 2011. From December 1992 to June 2008, he held various technical and human resources positions at subsidiaries of Shell plc (NYSE: SHEL), in both the upstream and downstream industries, and served as a director of Shell Company of Thailand Limited from February 2004 to May 2008. He also served as a director of Energy Complex Company Limited, a company responsible for the construction and operational management of an office building complex, from April 2012 to August 2018 and PTT Digital Solutions Co., Ltd., an information and communication technology company, from March 2014 to August 2018. Mr. Mekavichai received a BS in Geography from Srinakharinwirot University and a diploma in Hydrographic Surveying from Plymouth Polytechnic, U.K. Mr. Mekavichai brings broad expertise in oil and gas operations, risk management, human resources, corporate development and information and technology to the board of directors. In addition, we believe that Mr. Mekavichai's extensive experience as an executive and director at international energy companies makes him qualified to serve on our board of directors.

Charles C. Miller III has served as a director of the Company since May 2020. He served as a director of Global Healthcare Exchange, a provider of exchange and other electronic services to health care providers and their suppliers, from June 2017 through December 2023, and Equideum Health, a Web3 person-centered healthcare and research network provider, from December 2021 to April 2024. Mr. Miller was an executive in the telecommunications industry from 1987 to 2013. From 2000 to 2014, he was Vice Chairman of Level 3 Communications where his responsibilities included corporate strategy, mergers and acquisitions, business development, marketing and information services. Prior to that, Mr. Miller was an executive officer of BellSouth Corporation from 1987 to 2000, where his roles included Senior Vice President, Corporate Strategy and Development, as well as President of BellSouth International, Inc. Before his telecommunications career, he practiced corporate law at King & Spalding LLP from 1979 to 1984 and Ropes & Gray LLP from 1977 to 1979. Mr. Miller received an AB from Harvard College and a JD from Harvard Law School. Mr. Miller brings broad expertise in strategic planning, business development and technology to the board of directors. In addition, we believe that Mr. Miller's U.S. public company board experience and legal expertise make him qualified to serve on our board of directors.

Sunit S. Patel has served as a director of the Company since September 2022. Since December 2023, Mr. Patel has served as a director of Crown Castle Inc. (NYSE: CCI), a wireless infrastructure company, and since February 2021, he has served as Chief Financial Officer of Ibotta, Inc., a consumer technology company. Prior to that, he served as Executive Vice President, Merger and Integration Lead, at T-Mobile US, Inc., a provider of mobile communications services, from October 2018 to April 2020. In addition, Mr. Patel served as Executive Vice President and Chief Financial Officer of CenturyLink, Inc., an international facilities-based communications company, from November 2017 to September 2018 and Executive Vice President and Chief Financial Officer of Level 3 Communications Inc. from 2003 until its merger with CenturyLink in November 2017. He also co-founded and served as Chief Financial Officer of Looking Glass Networks Inc., a facilities-based provider of metropolitan telecommunication transport services, from April 2000 to March 2003. Prior to that, he served in senior leadership positions in a number of telecom companies and began his professional career in investment banking. Mr. Patel received a B.S. in Chemical Engineering and Economics from Rice University and is a Chartered Financial Analyst (CFA). Mr. Patel brings broad experience in financial, accounting and technology matters and strategic planning and transactions to the board of directors. In addition, we believe that Mr. Patel's financial and accounting expertise, executive leadership experience and public company experience make him qualified to serve on our board of directors.

Anon Sirisaengtaksin has served as a director of the Company since May 2020. He has served as a director of Banpu (SET: BANPU) since April 2016 and an Executive Advisor to Banpu for its oil and gas business since 2014. He has also served as a director of Saha-Union Public Company Limited (SET: SUC), an investment company, since January 2020 and CIMB Thai Bank Public Company Limited (SET: CIMBT), a commercial bank in Thailand, since June 2020. In addition, he served as a director and Chief Executive Officer of PTT Global Chemical Public Company Limited (SET: PTTGC) from 2012 to 2013, President and Chief Executive Officer of PTT Exploration (SET: PTTEP) from 2008 to 2012, Senior Executive Vice President, Corporate Strategy and Development of PTT Public Company Limited ("PTT PCL") (SET: PTT) from 2002 to 2008, Executive Vice President, Natural Gas Supply and Trading, Gas Business Group, of PTT PCL from 2001 to 2002 and Deputy President, Natural Gas Marketing and Transmission of PTT Natural Gas Distribution Co., Ltd. from 1996 to 2001. Mr. Sirisaengtaksin received a BS in Geology from Chulalongkorn University and an MBA from Thammasat University. Mr. Sirisaengtaksin brings broad expertise in corporate leadership and strategic planning to the board of directors. In addition, we believe that Mr. Sirisaengtaksin's extensive experience as an executive at international energy companies makes him qualified to serve on our board of directors.

Sinon Vongkusolkit has served as a director of the Company since July 2022. He has served as Chief Executive Officer and director of Banpu (SET: BANPU) since April 2024. Mr. Vongkusolkit also currently serves as a director of various subsidiaries of Banpu, including as a director of PT. Indo Tambangraya Megah Tbk (IDX: ITMG) since March 2024, as a director of Banpu Power (SET: BPP) since April 2024, as a director for each of BOG Co., Ltd. and BNAC since May 2024, as a director of BPPUS since June 2024 and as a director of Banpu Ventures Pte. Ltd. since May 2022. He previously served as Chief Executive Officer of Banpu NEXT Co. Ltd. from July 2022 to December 2023. Prior to that, he served at Banpu in the Project Management Office team, where he executed financial and asset transactions, from January 2020 to June 2022. He also served as a financial analyst in the Corporate Finance team of Banpu, where he worked on funding for the Banpu group, from November 2014 to January 2020. Mr. Vongkusolkit received a BA in Business and Marketing Management from Oxford Brookes University and an MA in Global Management Finance from Regent's University London. Mr. Vongkusolkit brings broad expertise in strategic management and operations, including corporate finance, investments and project management, from his time at Banpu to the board of directors. In addition, we believe that Mr. Vongkusolkit's leadership skills, technological adeptness and growth mindset from his time at Banpu NEXT Co. Ltd. make him qualified to serve on our board of directors.

Controlled Company

We have applied to list our common stock on the NYSE under the symbol "BKV." Upon completion of this offering, BNAC will hold approximately % of our total outstanding shares of common stock (or approximately % if the underwriters exercise in full their option to purchase additional shares), comprising more than 50% of the voting power of our outstanding common stock. As a result, we will be a "controlled company" within the meaning of the corporate governance rules of the NYSE. As a "controlled company," we will be eligible to rely on exemptions from the obligation to comply with certain NYSE corporate governance requirements, including the requirements that:

- a majority of our board of directors consist of independent directors;
- we have a corporate governance and nominating committee that is composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities; and
- we have a compensation committee that is composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities.

These exemptions do not modify the independence requirements for our audit committee. As a controlled company, we will remain subject to the rules of the Sarbanes-Oxley Act and the NYSE that require us to have an audit committee composed entirely of independent directors. Under these rules, we must have at least one independent director on our audit committee by the date our common stock is listed on the NYSE, at least two independent directors on our audit committee within 90 days of the listing date, and at least three independent directors on our audit committee within one year of the listing date. We expect to have four independent directors upon the closing of this offering.

While BNAC continues to control more than 50% of the voting power of our outstanding common stock, we qualify for, and intend to rely on, these exemptions. Accordingly, you will not have the same protections afforded to stockholders of companies that are subject to all of the corporate governance requirements of the NYSE.

If we cease to be a controlled company within the meaning of the applicable rules of the NYSE, we will be required to comply with these requirements after specified transition periods.

Board of Directors

We currently have twelve directors on our board of directors.

Pursuant to our Stockholders' Agreement, for so long as BNAC and Banpu beneficially own 10% or more of our voting stock, BNAC will be entitled to designate for nomination to our board of directors a number of individuals approximately proportionate to such beneficial ownership, provided that (i) from the completion of this offering until the first anniversary of the completion of this offering, at least three board seats will not be BNAC designees, (ii) from and after the first anniversary of the completion of this offering until the first date on which BNAC and Banpu beneficially own 50% or less of our voting stock, at least four board seats will not be BNAC designees, and (iii) from and after the first date on which BNAC and Banpu beneficially own 50% or less of our voting stock, a number of board seats equal to the minimum number of directors that would constitute a majority of the total number of directors comprising our board of directors will not be BNAC designees. The BNAC designees are Messrs. Kalnin, Davis, C. Vongkusolkit, Dayananda, Mekavichai, Sirisaengtaksin and S. Vongkusolkit and Ms. Chaimongkol.

Our board of directors will be divided into three classes of directors, with each class to be as equal in number as possible, and with the directors serving staggered three-year terms. The term of office of the Class I directors, consisting of Messrs. Kalnin, C. Vongkusolkit and Sirisaengtaksin and Ms. Chaimongkol, will expire at our first annual meeting of stockholders following the completion of this offering. The term of office of the Class II directors, consisting of Messrs. Dayananda, Mekavichai and Patel and Ms. Mashinski, will expire at our second annual meeting of stockholders following the completion of this offering. The term of office of the Class III directors, consisting of Messrs. Davis, Limpaphayom, Miller and S. Vongkusolkit, will expire at our third annual meeting of stockholders following the completion of this offering. See "*Description of Capital Stock — Anti-Takeover Provisions — Classified Board of Directors*" for more information.

Director Independence

Upon completion of this offering, we expect the following four members of our board of directors will qualify as "independent" under the listing standards of the NYSE: Messrs. Davis, Miller and Patel and Ms. Mashinski.

Committees of the Board of Directors

Our board of directors will establish standing committees in connection with the discharge of its responsibilities. Upon the completion of this offering, these committees will include an Audit & Risks Committee, a Compensation Committee and a Nominations & Governance Committee. The composition and responsibilities of each of the committees of our board of directors are described below. Members will serve on these committees until their resignation or until as otherwise determined by our board of directors.

Audit & Risks Committee

The Audit & Risks Committee will oversee the conduct of our financial reporting processes, including (i) reviewing with management and the outside auditors the audited financial statements included in our annual reports filed with the SEC, (ii) reviewing with management and the outside auditors the interim financial results included in our quarterly reports filed with the SEC, (iii) discussing with management and the outside auditors the quality and adequacy of internal controls and (iv) reviewing the independence of the outside auditors.

Our Audit & Risks Committee will have a minimum of three members. Upon the completion of this offering, we expect the members of our Audit & Risks Committee will be Ms. Mashinski, Ms. Chaimongkol and Mr. Patel, and Ms. Mashinski will serve as the chair of the Audit & Risks Committee. All members of our Audit & Risks Committee are required to be "independent" as defined in the NYSE corporate governance standards and Rule 10A-3 of the Exchange Act, subject to transitional relief during the one-year period following the effectiveness of the registration statement of which this prospectus forms a part. Those rules permit us to have an audit committee that has one independent member by the date our common stock first trades on the NYSE, a majority of independent members within 90 days of the effectiveness of the registration statement of which this prospectus forms a part and all independent members within one year of the effective date. Our board of directors has determined that each of Mr. Patel and Ms. Mashinski is independent under the NYSE corporate governance standards and Rule 10A-3 of the Exchange Act. All members of our Audit & Risks Committee will, in the judgment of our board of directors, be financially literate, or become so within a reasonable period of time after appointment to the Audit & Risks Committee, and at least one member of the Audit & Risks Committee will qualify as an "audit committee financial expert" as defined under the Sarbanes-Oxley Act and applicable SEC regulations. The Audit & Risks Committee will operate under a written charter that satisfies the applicable rules and regulations of the SEC and the listing standards of the NYSE, and the Audit & Risks Committee will review the charter annually. A copy of the Audit & Risks Committee Charter will be available for review on the Company's website.

Nominations & Governance Committee

The Nominations & Governance Committee will be responsible for (i) advising our board of directors about the appropriate composition of our board of directors and its committees, (ii) identifying and evaluating candidates for board service, (iii) recommending director nominees for election at annual meetings of stockholders or for appointment to fill vacancies and newly created directorships, and (iv) recommending the directors to serve on each committee of our board of directors. The Nominations & Governance Committee will also be responsible for periodically reviewing and making recommendations to our board of directors regarding corporate governance policies and responses to stockholder proposals, for conducting an annual performance review of our board of directors and its committees, and for reviewing whether our directors satisfy applicable independence requirements. Pursuant to our Stockholders' Agreement, BNAC, through ownership interests in us held by BNAC and its affiliates, will have certain rights to designate individuals for nomination to our board of directors, subject to applicable corporate governance rules of the SEC and the NYSE (which may require BNAC to designate independent directors). See "*Certain Relationships and Related Party Transactions — Stockholders' Agreement*."

Upon the completion of this offering, we expect the members of our Nominations & Governance Committee will be Messrs. Sirisaengtaksin, Davis, Dayananda and Mekavichai, and Mr. Sirisaengtaksin will serve as the chair of the Nominations & Governance Committee. As a "controlled company," our Nominations & Governance Committee is not required to be comprised of entirely independent directors. The Nominations & Governance Committee will operate under a written charter that satisfies the applicable rules and regulations of the SEC and the listing standards of the NYSE, and the Nominations & Governance Committee will review the charter annually. A copy of the Nominations & Governance Committee Charter will be available for review on the Company's website.

Compensation Committee

The Compensation Committee will review, evaluate and recommend to our board of directors compensation policies with respect to our directors, executive officers and senior management. The Compensation Committee will also administer the 2022 Plan. The Compensation Committee will have the authority to approve the compensation of the directors, executive officers and senior management of the Company. The Compensation Committee will also have the authority to grant equity awards under the 2022 Plan.

Upon the completion of this offering, we expect the members of our Compensation Committee will be Ms. Chaimongkol, Ms. Mashinski and Mr. Miller, and Ms. Chaimongkol will serve as the chair of the Compensation Committee. As a "controlled company," our Compensation Committee is not required to be comprised of entirely independent directors. The Compensation Committee will operate under a written charter that satisfies the applicable rules and regulations of the SEC and the listing standards of the NYSE, and the Compensation Committee will review the charter annually. A copy of the Compensation Committee Charter will be available for review on the Company's website.

Compensation Committee Interlocks and Insider Participation

None of our executive officers serve on the board of directors or compensation committee of another public company that has an executive officer that serves on our board or compensation committee. No member of our board is an executive officer of another public company in which one of our executive officers serves as a member of the board of directors or compensation committee of that company.

Code of Business Conduct and Ethics

Upon the completion of this offering, our board of directors will adopt a new Code of Business Conduct and Ethics applicable to all the Company's employees, officers and directors. The Code of Business Conduct and Ethics will cover compliance with law; fair and honest dealings with the Company, its competitors and others; full, fair and accurate disclosure to the public; and procedures for compliance with the Code of Business Conduct and Ethics. This Code of Business Conduct and Ethics will be available on the Company's website.

Corporate Governance Guidelines

Upon the completion of this offering, our board of directors will adopt corporate governance guidelines in accordance with the corporate governance rules of the NYSE.

Conflicts of Interest

We, Banpu and our respective affiliates have direct and indirect interests in subsidiaries, joint ventures and other companies which are engaged in a broad array of industries, including the acquisition, exploration, development and production of oil and gas reserves and electricity generation. Conflicts may arise from our affiliation with Banpu or its related companies, including BNAC and BPPUS. For example, Chris Kalnin, our Chief Executive Officer and Director, serves as a member of Banpu's Executive Committee. The Banpu Executive Committee's responsibilities include, among other things, developing an integrated plan for Banpu's transformation toward becoming an international versatile energy provider, ensuring Banpu's strategy in the countries in which it operates and realigning key organization processes. In particular, Mr. Kalnin will oversee all aspects of Banpu's business in North America, develop its growth strategy and business strengths in North America and seek opportunities for synergies among products and business of Banpu in North America. Mr. Kalnin will not receive any additional compensation or ancillary benefits from Banpu as a result of this role and our board of directors has waived any provisions of Mr. Kalnin's employment agreement and award agreements under our equity compensation plans that could be deemed to be violated by Mr. Kalnin serving on Banpu's Executive Committee.

In addition, in recognition that each of BKV and Banpu or any of its affiliates may desire to pursue the same or similar business opportunities, and in light of Mr. Kalnin's role on Banpu's Executive Committee, our board of directors has adopted a corporate opportunity policy that requires Mr. Kalnin to present applicable business opportunities of which he may become aware to our company before such opportunities may be presented to Banpu or one of its affiliates and, in connection therewith, our board of directors established an Opportunity Committee consisting entirely of independent directors, who are also independent of Banpu, to evaluate such opportunities. If an applicable business opportunity is presented to our company for consideration and the Opportunity Committee, after consultation with management or other persons as the members thereof determine advisable or appropriate, determines by majority vote to decline and reject such opportunity, only then may Mr. Kalnin present such opportunity to Banpu or one or more of its affiliates. Certain business opportunities will not be considered applicable, such as business opportunities that BKV is neither financially or legally able, nor contractually permitted, to undertake, that are not in BKV's line of business or in which BKV has no reasonable expectancy. Furthermore, business opportunities presented or submitted to the BKV-BPP Power Joint Venture will not violate the corporate opportunity policy.

Certain of our other personnel also serve as officers, directors, agents and/or consultants of Banpu, its related companies or other companies and, following this offering, seven of our directors will be employees of Banpu and its affiliates. Such persons have duties to Banpu or such other company or their respective stockholders and may have conflicts of interest or the appearance of conflicts of interest with respect to matters involving or affecting us and Banpu or any of the other companies to which they owe duties or other contractual obligations. Our certificate of incorporation provides that, to the fullest extent permitted by law, neither Banpu nor its affiliates or any director who is not employed by us (including any non-employee director who serves as one of our officers in both his or her director and officer capacities) or his or her affiliates will have any duty to refrain from (i) engaging in the same or similar business activities or lines of business in which we or our affiliates now engage or propose to engage or (ii) otherwise competing with us or our affiliates. In addition, in the event that Banpu or its affiliates or any non-employee director acquires knowledge of a potential transaction or other business opportunity that may be a corporate opportunity for itself, himself or herself or its or his or her affiliates or for us or any of our affiliates, such person will have no duty to communicate or offer such transaction or business opportunity to us or any of our affiliates and they may take any such opportunity for themselves or offer it to another person or entity. Our certificate of incorporation also renounces, to the fullest extent permitted by law, any interest or expectancy that we have in, or right to be offered an opportunity to participate in, specified business opportunities that are from time to time presented to our officers, directors or stockholders or their respective affiliates, other than those officers, directors, stockholders or affiliates who are our or our subsidiaries' employees. There can be no assurance that Banpu and its affiliates will not engage in competition with us in the future.

EXECUTIVE COMPENSATION

This section describes the material elements of compensation awarded to, earned by or paid to the following named executive officers (our "NEOs") for calendar years 2023 and 2022:

- Christopher P. Kalnin, Chief Executive Officer and interim Chief Financial Officer
- John T. Jimenez, Chief Financial Officer
- Eric S. Jacobsen, Chief Operating Officer

Summary Compensation Table

Name and Position (as of December 31, 2023)	Year	Salary ($)	Bonus ($)	Stock awards ($)[(1)]	Nonequity incentive plan compensation ($)[(2)]	All other compensation ($)[(3)]	Total ($)
Christopher Kalnin	2023	692,692	—	—	772,800	19,860	1,485,352
Chief Executive Officer	2022	510,000	—	—	800,700	18,383	1,329,083
John Jimenez	2023	398,346	—	—	308,016	19,860	726,222
Chief Financial Officer	2022	357,000	—	—	210,183	18,376	585,559
Eric Jacobsen	2023	424,500	—	—	380,052	17,731	822,283
Chief Operating Officer	2022	412,000	—	—	223,159	18,383	653,542

(1) At the time the 2021 Plan was adopted and approved, TRSUs were expected to be granted in four annual grants over a four-year period. Each of Messrs. Kalnin, Jimenez and Jacobsen, received their first annual grant of TRSUs in 2021, their second annual grant of TRSUs in 2022 and their third annual grant in 2023. In accordance with FASB ASC 718, for accounting purposes, the Company recognized a compensation expense in 2021 for each of the four annual grants expected to be granted during the four-year period, although only the first annual grant was granted in 2021. Therefore, although Messrs. Kalnin, Jimenez and Jacobsen were granted TRSUs in 2022 and 2023, because the Company was required to recognize the compensation expense for all TRSUs expected to be granted under the 2021 Plan in 2021, no grant date fair value for TRSUs granted to the NEOs in 2022 and 2023 is reflected in the table above. Messrs. Kalnin and Jacobsen also received a grant of PRSUs in 2021, with a performance period that ended on December 31, 2023. The grant date fair value of the TRSUs and PRSUs, computed in accordance with FASB ASC 718 (which viewed all four annual TRSU grants and the PRSU grant as being granted in 2021), plus the incremental cost associated with a modification made to the awards in November 2021, was $16,896,074 for Mr. Kalnin, $8,009,952 for Mr. Jimenez and $9,591,205 for Mr. Jacobsen. For more details relating to the assumptions used in calculating the grant date fair value of the TRSUs and PRSUs reported in this column, including modifications made thereto in November 2021, see "*Note 12 — Equity-Based Compensation*" to our audited consolidated financial statements included elsewhere in this prospectus. For more details relating to the TRSUs and PRSUs granted to Messrs. Kalnin, Jimenez and Jacobsen in 2021, 2022 and 2023, see "*— Equity Awards Granted Under our 2021 Long-Term Incentive Plan*" below.

(2) Amounts reported represent each NEO's annual performance-based bonus earned in 2022 or 2023 but paid after the end of the applicable fiscal year, upon certification of the applicable performance measures by our Compensation Committee. See "*— Annual Performance-Based Bonuses*" for more information.

(3) Amounts reported include the amounts paid to the NEOs shown in the following table:

	Company 401(k) Contribution ($)[a]	Life Insurance Premiums ($)[b]
Christopher P. Kalnin	19,800	60
John T. Jimenez	19,800	60
Eric S. Jacobsen	17,671	60

(a) The Company maintains a 401(k) plan that provides employees with an opportunity to save for retirement. From January 1, 2023 until April 23, 2023 and again from December 1, 2023 through the end of December 2023, the Company made matching contributions of up to 6% of base salary attributable to such periods, which contributions are immediately vested.

(b) Included in this column are the life insurance premiums paid on behalf of each NEO.

Employment Agreements

CEO Employment Agreement

Mr. Kalnin and the Company entered into an employment agreement effective as of August 4, 2020 (the "CEO Employment Agreement"), which provides Mr. Kalnin with, among other things, (1) an annual base salary of $500,000, subject to annual review by our board of directors, which, following such review was increased in 2022 to $510,000 and in 2023 to $700,000, (2) the eligibility to receive an annual cash bonus, which, following approval by our board of directors in 2022, was set for 2023 at a target amount equal to 120% of his base salary, but paid at an amount commensurate with the level at which the applicable performance goals are achieved (which may be higher or lower than the target level) and subject to continued employment through the end of the year, and (3) the opportunity to participate in the Company's equity incentive plan, with an annual restricted stock unit ("RSU") award to be made in each of 2021, 2022 and 2023 (each an "Annual RSU Grant") that is equal to at least 325,900 RSUs per year (which number has not been adjusted to give effect to the October 2023 one-for-two reverse stock split); subject to the terms of the applicable plan. Mr. Kalnin's Annual RSU Grant has been satisfied in accordance with the 2021 Plan, by reference to Mr. Kalnin's aggregate four-year Annual RSU Grant opportunity, with such RSUs granted approximately 70% on January 1, 2021 in the form of PRSUs and the remaining 30% in the form of TRSUs, with the first, second, third and fourth annual grants of TRSUs granted on each of January 1, 2021, January 1, 2022, January 1, 2023, and January 1, 2024. Each of the TRSU annual grants are subject to vesting requirements once granted, as described in more detail below in "— *Equity Awards Granted Under Our 2021 Long Term Incentive Plan*" and "— *Outstanding Equity Awards at Fiscal Year-End*." Mr. Kalnin is also eligible to participate in and receive benefits offered to our employees, including paid and holiday time off, health insurance coverage and participation in our 401(k) plan. Mr. Kalnin is subject to customary confidentiality and invention assignment covenants, as well as non-competition and non-solicitation covenants which extend for 18 months after termination of employment. Additionally, Mr. Kalnin may receive compensation and benefits in connection with a termination of his employment or a change in control, which are discussed below in "— *Potential Payments Upon Termination or Change in Control — Separation Benefits in the CEO Employment Agreement*."

CFO Employment Agreement

Mr. Jimenez and the Company entered into an employment agreement effective as of January 11, 2021 (the "CFO Employment Agreement"), pursuant to which Mr. Jimenez assumed the role of the Company's Chief Financial Officer as of April 16, 2021 and which provides Mr. Jimenez with, among other things, (1) an annual base salary of $350,000, which was increased in 2022 to $357,000 and in 2023 to $400,000, (2) the opportunity to receive a discretionary annual cash bonus based on the Company's performance (and taking into account Mr. Jimenez's individual effort and satisfactory achievement of established performance goals), which, following approval by our board of directors in 2022, was set for 2023 at a target amount equal to 95% of his base salary, and (3) the opportunity to participate in the 2021 Plan, subject to the 2021

Plan not being terminated, which was originally estimated to equate to equity awards with respect to approximately 618,000 shares over a four-year period (which number has not been adjusted to give effect to the October 2023 one-for-two reverse stock split) and, which awards would be subject to the terms of the 2021 Plan, adjustment to give effect to the October 2023 one-for-two reverse stock split and ultimately dependent on Company performance and Mr. Jimenez's individual effort and satisfactory achievement of performance goals. Mr. Jimenez is also eligible to participate in and receive benefits offered to other employees, including paid and holiday time off, health insurance coverage and participation, with a company match, in our 401(k) plan. Mr. Jimenez is subject to customary confidentiality and invention assignment covenants, as well as non-disparagement, non-competition and non-solicitation covenants which extend for 12 months after termination of employment. Additionally, Mr. Jimenez may receive compensation in connection with a termination of his employment, which is discussed below in "— *Potential Payments Upon Termination or Change in Control — Separation Benefits in the CFO Employment Agreement*."

COO Employment Agreement

Mr. Jacobsen and Kalnin Ventures entered into an employment agreement effective as of February 18, 2020 (the "COO Employment Agreement"), which provides Mr. Jacobsen with, among other things, (1) an annual base salary of $400,000, which was increased in 2022 to $412,000 and in 2023 to $425,000, and (2) the opportunity to receive a discretionary annual cash bonus based on the Company's performance (and taking into account Mr. Jacobsen's individual effort and satisfactory achievement of established performance goals), which, following approval by our board of directors in 2022, was set for 2023 at a target amount equal to 95% of his base salary. Mr. Jacobsen is also eligible to participate in and receive benefits offered to other employees, including paid and holiday time off, health insurance coverage and participation, with a company match, in our 401(k) plan. Mr. Jacobsen is subject to customary confidentiality and invention assignment covenants, as well as non-disparagement, non-competition and non-solicitation covenants. Additionally, Mr. Jacobsen may receive compensation in connection with a termination of his employment, which is discussed below in "— *Potential Payments Upon Termination or Change in Control — Separation Benefits in the COO Employment Agreement*."

Equity Awards Granted Under Our 2021 Long Term Incentive Plan

During the years ended December 31, 2021, December 31, 2022 and December 31, 2023, RSU awards were granted to our NEOs under the 2021 Plan, some of which are subject to service-based vesting conditions and some of which are subject to both performance-based and service-based vesting conditions. The descriptions of these RSU awards in this section have not been adjusted to give effect to our one-for-two reverse stock split that occurred on October 30, 2023. On January 1, 2021, Mr. Kalnin and Mr. Jacobsen were granted 97,770 and 55,500 TRSUs, respectively, and 912,520 and 518,000 PRSUs at the target payout level (which equate to 1,825,040 and 1,036,000 PRSUs at maximum payout level), respectively. On April 16, 2021, Mr. Jimenez was granted 46,350 TRSUs and 432,600 PRSUs at the target payout level (which equates to 865,200 PRSUs at maximum payout level). Approximately 25% of Messrs. Kalnin's and Jacobsen's TRSUs were vested at the time of grant and an additional 25% vested on each of January 1, 2022, January 1, 2023 and January 1, 2024. Approximately 25% of Mr. Jimenez's TRSUs were vested at the time of grant and an additional 25% vested on each of April 16, 2022 and April 16, 2023, with the remainder set to vest on April 16, 2024, subject to continued employment through such applicable vesting date. Messrs. Kalnin's, Jacobsen's and Jimenez's PRSUs vested based upon the level at which the performance measures described below in "— *BKV Corporation 2021 Long Term Incentive Plan*" were achieved over the period beginning January 1, 2021 and ending on December 31, 2023. On February 8, 2024, the Compensation Committee determined that such performance measures were achieved, and on February 15, 2024, the board of directors approved payout of the PRSUs, at 147.743% of target.

On January 1, 2022, Messrs. Kalnin and Jacobsen were granted 97,700 and 55,500 TRSUs, respectively, and on April 16, 2022, Mr. Jimenez was granted 46,350 TRSUs. Approximately 25% of Messrs. Kalnin's and Jacobsen's TRSUs were vested at the time of grant and an additional 25% vested on January 1, 2023 and January 1, 2024, with the remainder set to vest on January 1, 2025, subject to continued employment through such date. Approximately 25% of Mr. Jimenez's TRSUs were vested at the time of grant and an additional 25% vested on April 16, 2023, with the remainder set to vest in two substantially equal tranches on each of April 16, 2024 and April 16, 2025, in each case, subject to continued employment through such applicable vesting date.

On January 1, 2023, Messrs. Kalnin and Jacobsen were granted 97,770 and 55,500 TRSUs, respectively, and on April 16, 2023, Mr. Jimenez was granted 46,350 TRSUs. Approximately 25% of Messrs. Kalnin's and Jacobsen's TRSUs were vested at the time of grant and an additional 25% vested on January 1, 2024, with the remainder set to vest in two substantially equal tranches on each of January 1, 2025 and January 1, 2026, in each case, subject to continued employment through such applicable vesting date. Approximately 25% of Mr. Jimenez's TRSUs were vested at the time of grant and an additional 25% vested on April 16, 2024, with the remainder set to vest in two substantially equal tranches on each of April 16, 2025 and April 16, 2026, in each case, subject to continued employment through such applicable vesting date.

Annual Performance-Based Bonuses

For 2022 and 2023, our Compensation Committee recommended and our board of directors approved the adoption of an annual, performance-based bonus program for all of our employees, including each of our NEOs (the "2022 Annual Bonus" and the "2023 Annual Bonus," respectively, and collectively, the "Annual Bonuses"). Messrs. Kalnin, Jimenez and Jacobsen were assigned a target bonus opportunity for each of their 2022 Annual Bonuses equal to, for Mr. Kalnin, 100% of his base salary and for Messrs. Jimenez and Jacobsen, 30% of each of their respective base salaries and for each of their 2023 Annual Bonuses equal to, for Mr. Kalnin, 120% of his base salary and for Messrs. Jimenez and Jacobsen, 95% of each of their respective base salaries. Each NEO's Annual Bonuses were calculated by multiplying the individual's base salary by his target bonus opportunity and multiplied by an additional two components: the corporate multiplier, based on corporate performance goals, which were based off of the KPI Scorecard (discussed below) for the applicable year, and an individual multiplier, based on individual performance goals determined by, for Mr. Kalnin, the board of directors, and for Messrs. Jimenez and Jacobsen, Mr. Kalnin, subject to approval by our board of directors, for each applicable year. Once both the corporate performance goals and the individual performance goals were scored and the corporate multiplier and individual multipliers were determined, the Annual Bonuses earned by each of Messrs. Kalnin, Jimenez and Jacobsen was equal to the product of their respective target bonus opportunities and the corporate multiplier and individual multiplier assigned to the corporate performance goals and individual performance goals, respectively.

Company Performance Measures

The Company's performance metrics are based on the "KPI Scorecard," which, for the 2022 Annual Bonus, evaluated and for the 2023 Annual Bonus evaluated "lagging" indicators, "leading" indicators and "ESG" indicators that were weighted at an aggregate of 40%, 30% and 30%, respectively.

For the 2022 Annual Bonus, the "lagging" indicators measured the Company's shareholder value metrics, including the Company's EBITDA, net income, free cash flow, break-even unit costs, and the total net income related to the BKV-BPP Power Joint Venture. Each of these metrics comprised between 15% and 30% of the overall "lagging" indicator category. The "leading" indicators measured the Company's achievement of operational and strategic goals, including its net revenue interests production, estimated proved reserves at SEC Pricing, operational excellence (including the performance of its drilling and completion and restimulation programs and the level at which future projects inventory is clearly planned), the number of acquisition opportunities identified by the Company, the Company's automation and use of big data tools, and margin expansion through the use of daily pricing, hedges, storage sales and other means. Each of these metrics are weighted between 9% and 26% of the overall "leading" indicator category. The "ESG" indicators measured the Company's EHSR and ESG performance, including its Total Recordable Incident Rate (TRIR), major incidents, notices of violations (NOVs) from current year activity that could carry a penalty or fine, employee engagement, progress towards emission reduction targets, the satisfaction of three key goals derived from the 2021 employee engagement survey, the Company's performance of its ESG goals (including its MSCI ESG rating, completion of its sustainability report and the initiation of RSG sales), and reaching FID on a CCUS project. Each of these metrics are weighted between 10% and 38% of the overall "ESG" indicator category.

The Compensation Committee determined that the Company's shareholder value metrics were met, in the aggregate, at 161% of target, resulting in a company multiplier of 0.64 (or the product of the 161% level of achievement and the 40% weighting of such metrics). The Compensation Committee determined that the Company's operational and strategic goal metrics were met, in the aggregate, at 138% of target, resulting in a company multiplier of 0.41 (or the product of the 138% level of achievement with the 30% weighting of such metrics). The Compensation Committee determined that "ESG" indicators were met, in the aggregate at 171%, resulting in a company multiplier of 0.52 (or the product of the 171% level of achievement and the 30% weighting of such metrics). These determinations resulted in a company multiplier equal to 1.57.

For the 2023 Annual Bonus, the "lagging" indicators will measure the Company's shareholder value, which includes Adjusted EBITDAX, Adjusted Free Cash Flow, adjusted net income and break even unit costs. Each of these metrics comprises between 20% and 30% of the overall "lagging" indicator category. The "leading" indicators will measure the Company's achievement of operational and strategic goals, including total net sales production, year-end reserved, upstream/midstream capex delivery and people, leadership & culture. Each of these metrics comprises between 15% and 45% of the overall "leading" indicator category. The "ESG" indicators measures EHSR and ESG excellence and CCUS business delivery. Each of these metrics comprises between 40% and 60% of the overall "ESG" indicator category.

The Compensation Committee determined that the Company's shareholder value metrics were met, in the aggregate, at 41% of target, resulting in a company multiplier of 0.16 (or the product of the 41% level of achievement and the 40% weighting of such metrics). The Compensation Committee determined that the Company's operational and strategic goal metrics were met, in the aggregate, at 195% of target, resulting in a company multiplier of 0.59 (or the product of the 195% level of achievement with the 30% weighting of such metrics). The Compensation Committee determined that "ESG" indicators were met, in the aggregate at 89%, resulting in a company multiplier of 0.27 (or the product of the 89% level of achievement and the 30% weighting of such metrics). While these determinations resulted in a company multiplier equal to 1.02, the Compensation Committee exercised its discretion to set the company multiplier equal to 0.92 due to a treatment of depreciation, depletion, and amortization expenses in break-even unit costs.

Individual Performance Measures

For both the 2022 Annual Bonus and the 2023 Annual Bonus, the Compensation Committee set Mr. Kalnin's individual performance measures to be the same as the KPI Scorecard used for the company performance measures. The Compensation Committee determined for the 2022 Annual Bonus that Mr. Kalnin's individual contributions to the KPI Scorecard, along with his guiding the Company to be ready for an IPO and the Company's employee satisfaction (measured through a survey of the employees) resulted in an individual multiplier of 1.00, which the board of directors approved. The Compensation Committee determined for the 2023 Annual Bonus that Mr. Kalnin's individual contributions to the KPI Scorecard, resulted in an individual multiplier of 0.92, which the board of directors approved.

Mr. Kalnin set Messrs. Jimenez's and Jacobsen's individual performance goals for both of their 2022 Annual Bonus and 2023 Annual Bonus to be based off the elements of the KPI Scorecard that directly related to each of their duties.

For Mr. Jimenez's 2022 Annual Bonus, Mr. Jimenez's individual performance goals included his leadership, people and culture skills, his finance and accounting foundational processes and his IPO readiness. With respect to Mr. Jimenez's 2022 Annual Bonus, Mr. Kalnin recommended to the board of directors that, based on growth of the finance and accounting teams, IPO readiness, the development of relationships with investors and financial institutions, Mr. Jimenez's individual multiplier should be 1.25, which the board of directors approved. For Mr. Jimenez's 2023 Annual Bonus, Mr. Jimenez's individual performance goals included his leadership, people and culture skills, IPO readiness, his review of system strategies and financial solutions to enable the company's continued growth, and his contributions towards initiatives to improve the company's operational efficiencies and commercial optimization and towards the continued development of the company's IT organization. With respect to Mr. Jimenez's 2023 Annual Bonus, Mr. Kalnin recommended to the board of directors that, based on financial reporting process improvements and a successful debt financing, Mr. Jimenez's individual multiplier should be 0.92, which the board of directors approved.

For Mr. Jacobsen's 2022 Annual Bonus, Mr. Jacobsen's individual performance goals included his leadership, people and culture skills, his ESG foundations and his IPO readiness, and growth of the CCUS business. With respect to Mr. Jacobsen's 2022 Annual Bonus, Mr. Kalnin recommended to the board of directors that, based on growth of the CCUS business, development of the data analysis program, successful

M&A integration and an award-winning sustainability report, Mr. Jacobsen's individual multiplier should be 1.15, which the board of directors approved. For Mr. Jacobsen's 2023 Annual Bonus, Mr. Jacobsen's individual performance goals included his leadership, people and culture skills, continued support of the company's ESG and EHSR initiatives, continued growth of the CCUS business and his work with the steering committee to develop certain projects and businesses. With respect to Mr. Jacobsen's 2023 Annual Bonus, Mr. Kalnin recommended to the board of directors that, based on strong base production development performance and growth of the CCUS business, Mr. Jacobsen's individual multiplier should be 1.08, which the board of directors approved.

Outstanding Equity Awards at Fiscal Year-End

The following table presents the outstanding equity awards held by each of our NEOs as of December 31, 2023, which amounts are reflective of the impact of our one-for-two reverse stock split completed on October 30, 2023. The values are based on a share price of $28.25 per share, which is the per share value as of December 31, 2023.

	Stock Awards			
Name	Number of shares or units of stock that have not vested (#)	Market value of shares or units of stock that have not vested ($)	Equity incentive plan awards: Number of unearned shares, units or other rights that have not vested (#)	Equity incentive plan awards: Market or payout value of unearned shares, units or other rights that have not vested ($)
Christopher P. Kalnin	—	—	456,260(1)	12,889,345
Christopher P. Kalnin	36,664(2)	1,035,758	—	—
Christopher P. Kalnin	24,442(3)	690,487	—	—
Christopher P. Kalnin	12,222(4)	345,272	—	—
John T. Jimenez	—	—	216,300(1)	6,110,475
John T. Jimenez	17,381(5)	491,014	—	—
John T. Jimenez	11,587(6)	327,333	—	—
John T. Jimenez	5,794(7)	163,681	—	—
Eric S. Jacobsen	—	—	259,000(1)	7,316,750
Eric S. Jacobsen	20,812(2)	587,939	—	—
Eric S. Jacobsen	13,875(3)	391,969	—	—
Eric S. Jacobsen	6,937(4)	195,971	—	—

(1) In accordance with SEC rules, represents the maximum number of PRSUs outstanding as of December 31, 2023 (assuming the performance goals are determined to be met at maximum), as it is anticipated that the PRSU KPIs will be met at a level at least equal to target performance. On February 8, 2024, the Compensation Committee determined that the PRSUs were earned, and the board of directors approved payout of the PRSUs, at 147.743% of target performance.

(2) Represents the portion of the TRSUs granted on January 1, 2023 to Messrs. Kalnin and Jacobsen that remained outstanding and unvested as of December 31, 2023, approximately one-third of which vested or vest, as applicable, on each of January 1, 2024, January 1, 2025 and January 1, 2026.

(3) Represents the portion of the TRSUs granted on January 1, 2022 to Messrs. Kalnin and Jacobsen that remained outstanding and unvested as of December 31, 2023, approximately one-half of which vested or vest, as applicable, on each of January 1, 2024 and January 1, 2025.

(4) Represents the portion of the TRSUs granted on January 1, 2021 to Messrs. Kalnin and Jacobsen that remained outstanding and unvested as of December 31, 2023, which vested on January 1, 2024.

(5) Represents the portion of the TRSUs granted on April 16, 2023 to Mr. Jimenez that remained outstanding and unvested as of December 31, 2023, approximately one-third of which vest on each of April 16, 2024, April 16, 2025 and April 16, 2026.

(6) Represents the portion of the TRSUs granted on April 16, 2022 to Mr. Jimenez that remained outstanding and unvested as of December 31, 2023, approximately one-half of which vest on each of April 16, 2024 and April 16, 2025.

(7) Represents the portion of the TRSUs granted on April 16, 2021 to Mr. Jimenez that remained outstanding and unvested as of December 31, 2023, which vest on each April 16, 2024.

Potential Payments Upon Termination or Change in Control

Separation Benefits in the CEO Employment Agreement

The CEO Employment Agreement provides that, if Mr. Kalnin's employment with the Company is terminated by the Company without "cause" or by Mr. Kalnin with "good reason," (1) any outstanding RSUs granted pursuant to his Annual RSU Grant will become vested and (2) Mr. Kalnin will receive a lump sum payment equal to 200% of the sum of (a) his base salary plus (b) his target annual cash bonus, each in effect at the time of Mr. Kalnin's termination. If Mr. Kalnin elects coverage under the Company's medical plan pursuant to COBRA, Mr. Kalnin will be reimbursed for the full amount of his and his eligible dependents' COBRA premiums for the 18-month period following his termination, unless he earlier becomes eligible for coverage under another employer's medical plan (together with the Annual RSU Grant acceleration and lump sum payment, the "CEO Separation Benefits"). "Cause," as defined in the CEO Employment Agreement, means Mr. Kalnin's (i) indictment for a felony or his commission of fraud against the Company; (ii) misconduct that brings the Company into substantial public disgrace or disrepute; (iii) gross negligence or gross misconduct with respect to the Company; (iv) insubordination to, or material failure to follow lawful directions of, the board of directors, in either case if not cured within 10 days of Mr. Kalnin's receipt of written notice of such event; (v) material violation of the restrictive covenants in the CEO Employment Agreement; (vi) material breach of any Company work rule or internal policy that is not cured within 10 days of Mr. Kalnin's receipt of written notice of such event (if such event can be cured); (vii) a violation of the Foreign Corrupt Practices Act of 1977 or any state or federal anti-money laundering laws; or (viii) material breach of the CEO Employment Agreement that is not cured within 30 days of Mr. Kalnin's receipt of written notice of such breach. "Good Reason," as defined in the CEO Employment Agreement, means (i) a material reduction in Mr. Kalnin's base salary or target annual bonus (other than as part of an across-the board reduction of no more than 10% applicable to all of the Company's executives); (ii) a material diminution in Mr. Kalnin's position, duties, authority, reporting or responsibilities; (iii) the Company's material breach of the CEO Employment Agreement; or (iv) the involuntary permanent relocation of Mr. Kalnin's principal place of business to a location more than 35 miles beyond the Company's current place of business.

Mr. Kalnin's receipt of the CEO Separation Benefits is subject to his execution and non-revocation of a release of claims in favor of the Company and his continued compliance with the restrictive covenants contained in the CEO Employment Agreement. Such restrictive covenants include non-competition, non-solicitation (of both employees or customers) and intellectual development prohibitions for 18 months following termination, along with a perpetual confidentiality prohibition.

Separation Benefits in the CFO Employment Agreement

The CFO Employment Agreement provides that, if Mr. Jimenez's employment with the Company is terminated by the Company without "cause" (as defined in the CFO Employment Agreement), Mr. Jimenez will receive 18 months of base salary, subject to his execution of a separation agreement and general release and his compliance with a 12-month non-competition and non-solicitation restriction.

Separation Benefits in the COO Employment Agreement

The COO Employment Agreement provides that, if Mr. Jacobsen's employment with the Company is terminated by the Company without "cause" (as determined by the Company in good faith), Mr. Jacobsen will receive a lump sum payment equal to three months of his base salary.

BKV Corporation 2021 Long Term Incentive Plan

The 2021 Plan was initially adopted by our board of directors on January 1, 2021 and was amended in November 2021. The 2021 Plan terminated pursuant to its terms on January 1, 2024 and no further awards will be made thereunder. Termination of the 2021 Plan will not affect the Company's or participants' rights, which will remain in full force and effect, as to all outstanding unvested or vested awards, and shares of common stock issued in settlement of awards.

Purpose. The purpose of the 2021 Plan was to permit the grant of awards to our directors and employees of our Company or any of our subsidiaries, and to attract and retain such individuals who contribute to the achievement of the Company's economic objectives.

Administration. Our 2021 Plan was administered by our Compensation Committee (for purposes of this section, the "Committee") and subject to the board of director's approval. Subject to the terms of the 2021 Plan, the administrator had the authority to, among other things, select the persons to whom awards are granted, determine the nature, extent and timing of the awards to be granted, determine the duration of and restrictions and other conditions applicable to such awards. Any interpretation or determination by the Committee under the 2021 Plan will be final and conclusive. The Committee may delegate its administrative duties or powers to one or more of our officers.

Shares Available. Prior to our one-for-two reverse stock split completed on October 30, 2023, there were 14,941,176 shares of our common stock authorized for grant under the 2021 Plan. The shares available for issuance may be shares authorized but unissued or treasury shares. The Chief Executive Officer had the authority to grant up to 60% of the available shares on or before December 31, 2022 (assuming target payout of the PRSUs). Assuming target payout of the PRSUs and based on the TRSUs that were legally outstanding as of December 31, 2023, 3,114,435 shares were underlying outstanding equity awards and 3,315,320 shares remained available for issuance under the 2021 Plan as of such date (which numbers account for our one-for-two reverse stock split completed on October 30, 2023). Assuming payout of the PRSUs at 150% of target and based on the TRSUs that were legally outstanding as of December 31, 2023, 4,457,153 shares were underlying outstanding equity awards and 1,721,483 shares remained available for issuance under the 2021 Plan as of such date (which numbers account for our one-for-two reverse stock split completed on October 30, 2023). Following the grant on January 1, 2024 of TRSUs to certain of the Company's employees, including Messrs. Kalnin and Jacobsen, no more grants may be made under the 2021 Plan.

Share Counting. The aggregate number of shares of our common stock that were available for award under the 2021 Plan were reduced by one share of our common stock for every one share of our common stock subject to an award granted under the 2021 Plan. Shares of our common stock that were subtracted from the amount of available shares with respect to an award that ultimately lapsed, expired, was forfeited or for any reason was terminated or unvested were not automatically available again for issuance under the 2021 Plan.

Eligibility. Awards under the 2021 Plan could be granted to employees and directors of the Company or any of our subsidiaries. Eligible recipients who were either (1) the Chief Executive Officer or classified by the Company at the Senior Management level (those reasonably likely to be in the four most highly compensated during the next financial year or otherwise recommended by the Chief Executive Officer and approved by the board of directors as such) or (2) classified by the Company below the Senior Management level but who were recommended for an award by our Chief Executive Officer generally received PRSUs and TRSUs under the 2021 Plan.

Types of Awards Under the 2021 Plan. Pursuant to the 2021 Plan, we could grant TRSUs and PRSUs. Generally, with respect to the aggregate awards anticipated to be granted to participants over a four-year period, 70% of such aggregate award granted under the 2021 Plan were PRSUs and 30% were TRSUs.

Time-Vested Restricted Stock Units. The TRSUs were contemplated as being granted annually beginning on the effective date of the 2021 Plan and in each of the three (3) financial years thereafter or commencing upon an individual first becoming a participant under the 2021 Plan. The TRSUs were subject to the recipient's continued employment and are 25% vested on grant, with the remaining TRSUs vesting 25% on each of the first, second and third anniversaries of grant.

Performance-Vested Restricted Stock Units. The PRSUs were granted as a one-time grant on the effective date of the 2021 Plan or upon an individual first becoming a participant under the 2021 Plan. The PRSUs vest subject to the recipient's continued performance through the vesting date and based upon the level at which the performance metrics are attained, which metrics may be attained at a level between 0% and 200% of the target performance level. The performance period for the PRSUs began on the effective date of the 2021 Plan and ended on December 31, 2023. The performance measures include total shareholder return, return on capital employed and the Company's IPO readiness and were met at 147.743% of target performance, in the aggregate.

Effect of Termination or Forfeiture. Unless otherwise provided in an award agreement, or unless the Committee determines otherwise, upon a participant's termination for any reason, awards held by the participant that have not vested as of the date of his or her termination were forfeited. If the Committee determines that the participant has committed an act that would constitute cause or an adverse action (each as defined in the 2021 Plan), either before or after such participant's termination of employment and regardless of whether such participant was terminated for cause, the Committee in its sole discretion may require that the participant surrender and return to the Company all or any shares of common stock received prior to his or her termination in settlement of any vested award under the 2021 Plan or to disgorge all or any profits or any other economic value made or realized by the participant, during the period beginning one year before the participant's termination in connection with any shares of stock issued upon vesting of any TRSUs and PRSUs granted under the 2021 Plan.

Repurchase, Put and Drag-Along Rights. If a participant (1) committed a material breach of his or her employment agreement or service contract with the Company that was not capable of being remedied or, if capable of being remedied, that was not remedied by the participant within 30 days, or (2) was terminated for any reason, then the Company had the right, which remained open for 90 days following termination, to repurchase all (but not less than all) of the vested shares of common stock acquired by the participant under the 2021 Plan. The purchase price of the vested shares so repurchased was equal to the fair market value of the shares at the time of repurchase. Prior to this offering, if a participant's employment was terminated for any reason other than the participant's resignation or, if a participant's employment terminated due to his or her voluntary resignation and more than 36 months had passed since the participant's receipt of the first grant of an incentive award under the 2021 Plan, and, in each case, the Company had not repurchased the participant's shares of common stock acquired under the 2021 Plan, the participant had the right to elect to sell such shares back to the Company at an amount equal to the fair market value of the shares at the time the election to sell was made. In November 2021, both the Company's repurchase right and this put right were amended so that they could not be exercised for at least 181 days following the date the participant's award vests and shares are acquired pursuant to such award, and a "Sell Fund Purchase Program" was implemented whereby, if specifically provided for in an award agreement, participants have the ability to tender shares for repurchase by the Company. The "Sell Fund Purchase Program" expired on December 31, 2023 and the put right will be subject to the market stand-off provisions discussed below upon consummation of this offering. Additionally, if Banpu proposed to effect the sale of shares of common stock representing more than 80% of the total issued and outstanding shares of Banpu, it may have required the participation in such sale of all of the vested shares of common stock owned by participants.

Corporate Transactions; Change in Control. In the event of (1) any reorganization, merger, consolidation, recapitalization, liquidation, reclassification, stock dividend, stock split, combination of shares, rights offering, extraordinary dividend or divestiture or other similar change in corporate structure or shares, (2) any purchase, acquisition, sale, disposition or write-down of a significant amount of assets or a significant business, (3) any change in accounting principles or practices, tax laws or other such laws or provisions affecting reported results, (4) any uninsured catastrophic losses or extraordinary non-recurring items as described in Accounting Standards Codification 225-20, (5) an IPO or (6) any other similar change, in each case with respect to the Company or any other entity whose performance is relevant to the vesting of the PRSUs, the Committee may amend or modify the vesting criteria of any outstanding PRSUs to equitably reflect such event, with the desired result that the criteria for evaluating such financial performance of the Company or such other entity will be substantially the same following such event as prior to such event.

In the event of a Change in Control (as defined in the 2021 Plan), the board of directors or any corporation or entity assuming the obligations of the Company could have provided that awards outstanding under the 2021 Plan be vested in full or in part on the date of such Change in Control or could have provided that such awards be assumed or that an equivalent award be substituted by the acquiring or succeeding corporation. The performance period of the PRSUs would end as of the date of such Change in Control.

Transferability. Generally, awards under the 2021 Plan may not be transferred by a participant except by will or the laws of descent and distribution. However, the 2021 Plan allowed participants to designate a beneficiary that would receive payment or settlement of an award under the 2021 Plan in the event of the participant's death.

Market Standoff. Unless the Committee otherwise provides the participant with prior written consent, the 2021 Plan places market stand-off restrictions on shares of common stock acquired in connection with the grant, vesting or settlement of the PRSUs and TRSUs. The participant may not, without the consent of the Company or the representatives of any underwriters (for the duration determined by the Company and the representatives of the underwriters, but not to exceed 180 days from the date of the final prospectus), (1) sell, pledge, offer to sell, contract to sell, sell any option or contract to purchase, purchase any option or contract to sell, grant any option, right or warrant to purchase or otherwise transfer or dispose of, any shares of common stock or any securities convertible into or exercisable or exchangeable for common stock, or (2) enter into any swap or other arrangement that transfers to another, in whole or in part, any of the economic consequences of ownership of the common stock.

Amendment and Termination. The Committee has the authority to amend or modify for any reason the terms of any outstanding awards under the 2021 Plan, including the authority to modify the number of shares or other terms and conditions of an award, accept the surrender of an outstanding award or, to the extent to previously exercised or vested, authorize the grant of new awards in substitution for surrendered awards. However, the terms of any such amendments must be permitted by the 2021 Plan, and such amendment may not (1) cause the award to become taxable under Section 409A of the Code or (2) adversely affect any participant without such participant's consent.

BKV Corporation 2022 Equity and Incentive Compensation Plan

In anticipation of this offering, our board of directors adopted, and our stockholders approved, the 2022 Plan. The 2022 Plan will become effective immediately prior to the consummation of this offering. The material terms of the 2022 Plan are as follows:

Purpose. The purpose of the 2022 Plan is to permit the grant of awards to our directors, officers and other employees and certain consultants, and to provide to such persons incentives and rewards for service and/or performance.

Administration. The 2022 Plan will generally be administered by the Compensation Committee or any other committee of the board of directors designated by the board of directors to administer the 2022 Plan (for purposes of this section, the "Committee"). Under the 2022 Plan, the Committee has the authority to determine eligible participants in the 2022 Plan, and to interpret and make determinations under the 2022 Plan. Any interpretation or determination by the Committee under the 2022 Plan will be final and conclusive. The Committee may delegate its administrative duties or powers to one or more of our officers. However, the board of directors shall have the same powers and authorities as the Committee with respect to grants of awards to non-employee directors and may, in its discretion, act in lieu of the Committee with respect to such awards.

Shares Available for Awards under the 2022 Plan. After adjustments to give effect to our one-for-two reverse stock split completed on October 30, 2023, and subject to adjustment as described in the 2022 Plan, the number of shares of our common stock available for awards under the 2022 Plan is, in the aggregate, 5,000,000 shares of our common stock (which we refer to as the "Available Shares"), with such shares subject to adjustment to reflect any extraordinary cash dividend, stock dividend, split or combination of our common stock. The Available Shares may be shares of original issuance, treasury shares or a combination of the foregoing.

The 2022 Plan also contains limits on the maximum value at grant for awards to non-employee directors in any calendar year of $750,000.

Share Counting. The aggregate number of shares of our common stock available for award under the 2022 Plan will be reduced by one share of our common stock for every one share of our common stock subject to an award granted under the 2022 Plan.

Shares of our common stock subject to an award that is cancelled or forfeited, expires, is settled for cash or is unearned (in whole or in part) will be added back to the aggregate number of shares of our common stock available under the 2022 Plan; however, the following shares of our common stock will not be added back: (i) shares of our common stock withheld by us in payment of the exercise price of a stock option; (ii) shares of our common stock tendered or otherwise used in payment of the exercise price of a stock option; (iii) shares of our common stock withheld by us or tendered or otherwise used to satisfy a tax withholding obligation; (iv) shares of our common stock subject to share-settled appreciation rights that are not actually issued in connection with the settlement of such appreciation right; and (v) shares of our common stock reacquired by the Company on the open market or otherwise using cash proceeds from the exercise of stock options. In addition, if under the 2022 Plan a participant has elected to give up the right to receive cash compensation in exchange for shares of our common stock based on fair market value, such shares of our common stock will not count against the aggregate number of shares of our common stock available under the 2022 Plan.

Shares of our common stock issued or transferred pursuant to awards granted under the 2022 Plan in substitution for or in conversion of, or in connection with the assumption of, awards held by awardees of an entity engaging in a corporate acquisition or merger with us or any of our subsidiaries (which we refer to as "Substitute Awards") will not count against, nor otherwise be taken into account in respect of, the share limits under the 2022 Plan unless otherwise provided in the 2022 Plan. Additionally, shares of common stock available under certain plans that we or our subsidiaries may assume in connection with corporation transactions from another entity may be available for certain awards under the 2022 Plan, but will not count against, nor otherwise be taken into account in respect of, the share limits under the 2022 Plan.

Types of Awards Under the 2022 Plan. Pursuant to the 2022 Plan, we may grant stock options, appreciation rights, restricted stock, RSUs, performance shares, performance units, cash incentive awards, and certain other awards based on or related to shares of our common stock.

Each grant of an award under the 2022 Plan will be evidenced by an award agreement or agreements, which will contain such terms and provisions as the Committee may determine, consistent with the 2022 Plan. Those terms and provisions include the number of our shares of our common stock subject to each award, earning or vesting terms and any other terms consistent with the 2022 Plan. A brief description of the types of awards which may be granted under the 2022 Plan is set forth below.

Stock Options. Stock options granted under the 2022 Plan are non-qualified stock options and must have an exercise price per share that is not less than the fair market value of a share of our common stock on the date of grant. The term of a stock option may not extend more than 10 years after the date of grant. Each grant will specify the form of consideration to be paid in satisfaction of the exercise price.

Appreciation Rights. The 2022 Plan provides for the grant of appreciation rights. An appreciation right is a right to receive from us an amount equal to 100%, or such lesser percentage as the Committee may determine, of the spread between the base price and the value of shares of our common stock on the date of exercise. An appreciation right may be paid in cash, shares of our common stock or any combination thereof. Except with respect to Substitute Awards, the base price of an appreciation right may not be less than the fair market value of a share of common stock on the date of grant. The term of an appreciation right may not extend more than 10 years from the date of grant.

Restricted Stock. Restricted stock constitutes an immediate transfer of the ownership of shares of our common stock to the participant in consideration of the performance of services, entitling such participant to dividend, voting and other ownership rights, subject to the substantial risk of forfeiture and restrictions on transfer determined by the Committee for a period of time determined by the Committee or until certain management objectives specified by the Committee are achieved. Each such grant or sale of restricted stock may be made without additional consideration or in consideration of a payment by the participant that is less than the fair market value per share of our common stock on the date of grant. Any grant of restricted stock may specify the treatment of dividends or distributions paid on restricted stock that remains subject to a substantial risk of forfeiture. Any such dividends or other distributions on restricted stock shall be deferred until, and paid contingent upon, the vesting of such restricted stock.

Restricted Stock Units. RSUs awarded under the 2022 Plan constitute an agreement by us to deliver shares of our common stock, cash, or a combination thereof, to the participant in the future in consideration of the performance of services, but subject to the fulfillment of such conditions (which may include the achievement of management objectives) during the restriction period as the Committee may specify. Each grant or sale of RSUs may be made without additional consideration or in consideration of a payment by the participant that is less than the fair market value of shares of our common stock on the date of grant. During the applicable restriction period, the participant will have no ownership, transfer or voting rights in the shares of our common stock underlying the RSUs. Rights to dividend equivalents may be extended to and made part of any RSU award at the discretion of and on the terms determined by the Committee, provided that any dividend equivalents or other distributions on the shares of our common stock underlying the RSUs shall be deferred until and paid contingent upon the vesting of such RSUs. Each grant of RSUs will specify that the amount payable with respect to such RSUs will be paid in cash, shares of our common stock, or a combination of the two.

Cash Incentive Awards, Performance Shares, and Performance Units. Performance shares, performance units and cash incentive awards may also be granted to participants under the 2022 Plan. A performance share is a bookkeeping entry that records the equivalent of one share of our common stock, and a performance unit is a bookkeeping entry that records a unit equivalent to $1.00 or such other value as determined by the Committee. Each grant will specify the number or amount of performance shares or performance units, or the amount payable with respect to cash incentive awards, being awarded, which number or amount may be subject to adjustment to reflect changes in compensation or other factors.

These awards, when granted under the 2022 Plan, become payable to participants upon the achievement of specified management objectives and upon such terms and conditions as the Committee determines at the time of grant. Each grant will specify the management objectives regarding the earning of the award. Each grant will specify the time and manner of payment of cash incentive awards, performance shares or performance units that have been earned, and any grant may further specify that any such amount may be paid or settled in cash, shares of our common stock, or any combination thereof. Any grant of performance shares or performance units may provide for the payment of dividend equivalents in cash or in additional shares of our common stock, provided that such dividend equivalents shall be subject to deferral and payment on a contingent basis based on the earning and vesting of the performance shares or performance units, as applicable, with respect to which such dividend equivalents are paid.

Other Awards. The Committee may authorize the grant of such other awards (which we refer to as “other awards”) that may be denominated or payable in, valued in whole or in part by reference to, or otherwise based on, or related to, shares of our common stock or factors that may influence the value of such shares of our common stock, including, without limitation, convertible or exchangeable debt securities, other rights convertible or exchangeable into shares of our common stock, purchase rights for shares of our common stock, awards with value and payment contingent upon our performance or performance of specified subsidiaries, affiliates or other business units or any other factors designated by the Committee, and awards valued by reference to the book value of the shares of our common stock or the value of securities of, or the performance of our subsidiaries, affiliates or other business units.

Adjustments; Corporate Transactions. The Committee will make or provide for such adjustments in the: (i) number and kind of shares of our common stock covered by outstanding stock options, appreciation rights, restricted stock, RSUs, performance shares, performance units and, if applicable, other awards; (ii) exercise price or base price provided in outstanding stock options and appreciation rights; (iii) cash incentive awards; and (iv) other award terms, as the Committee determines to be equitably required in order to prevent dilution or enlargement of the rights of participants that otherwise would result from (a) any extraordinary cash dividend, stock dividend, stock split, combination of shares, recapitalization or other change in our capital structure, (b) any merger, consolidation, spin-off, spin-out, split-off, split-up, reorganization, partial or complete liquidation or other distribution of assets, issuance of rights or warrants to purchase securities or (c) any other corporate transaction or event having an effect similar to any of the foregoing.

In the event of any such transaction or event, or in the event of a change in control (as defined in the 2022 Plan), the Committee may provide in substitution for any or all outstanding awards under the 2022 Plan such alternative consideration (including cash), if any, as it may in good faith determine to be equitable under the circumstances and will require in connection therewith the surrender of all awards so replaced in a manner that complies with Section 409A of the Code. In addition, for each stock option or appreciation right with an exercise price greater than the consideration offered in connection with any such transaction or event or change in control, the Committee may in its discretion elect to cancel such stock option or appreciation right without any payment to the person holding such stock option or appreciation right. The Committee will make or provide for such adjustments to the number of shares available for issuance under the 2022 Plan and the share limits of the 2022 Plan as the Committee in its sole discretion may in good faith determine to be appropriate in connection with such transaction or event.

Transferability of Awards. Except as otherwise provided by the Committee, no stock option, appreciation right, restricted share, RSU, performance share, performance unit, cash incentive award, other award or dividend equivalents paid with respect to awards made under the 2022 Plan may be transferred by a participant except by will or the laws of descent and distribution.

Amendment and Termination of the 2022 Plan. Our board of directors generally may amend the 2022 Plan from time to time in whole or in part. However, if any amendment (i) would materially increase the benefits accruing to participants under the 2022 Plan, (ii) would materially increase the number of shares of our common stock which may be issued under the 2022 Plan, (iii) would materially modify the requirements for participation in the 2022 Plan, or (iv) must otherwise be approved by our stockholders in order to comply with applicable law or the rules of the NYSE, then such amendment will be subject to stockholder approval and will not be effective unless and until such approval has been obtained.

Our board of directors may, in its discretion, terminate the 2022 Plan at any time. Termination of the 2022 Plan will not affect the rights of participants or their successors under any awards outstanding and not exercised in full on the date of termination. No grant will be made under the 2022 Plan more than 10 years after the effective date of the 2022 Plan, but all grants made prior to such date shall continue in effect thereafter subject to the terms of the 2022 Plan.

BKV Corporation Employee Stock Purchase Plan

In anticipation of this offering, our board of directors adopted, and our stockholders approved, the ESPP. The ESPP is intended to qualify as an "employee stock purchase plan" under Section 423 of the Code. The ESPP will become effective immediately prior to the consummation of this offering. The material terms of the ESPP are as follows:

Purpose. The purpose of the ESPP is to provide employees of the Company and certain of its subsidiaries with an opportunity to acquire a proprietary interest in the Company through the purchase of shares of our common stock.

Administration. The ESPP will be administered by the Compensation Committee (for purposes of this section, the "Committee"). Subject to the terms of the ESPP, the Committee has complete discretion to establish the terms and conditions of offerings under the ESPP and the subsidiaries, if any, eligible to participate in such offerings, to interpret the ESPP and to make all decisions related to the operation of the ESPP. The board of directors has the same powers as the Committee and may act in lieu of the Committee with respect to the ESPP.

Shares Available for Issuance. After adjustments to give effect to our one-for-two reverse stock split completed on October 30, 2023, and subject to adjustment as described in the ESPP, the number of shares of our common stock available for awards under the ESPP is 500,000 shares of our common stock.

Eligibility. All employees who have been employed by the Company or a designated subsidiary (whether currently existing or subsequently established) for at least six months prior to the beginning of an Offering and who work at least 20 hours per week and more than five months per calendar year are eligible to participate in the ESPP, resulting in approximately 329 employees (including six executive officers) as eligible participants. The Committee may permit employees who work less than 20 hours per week or less than five months per year to participate and may exclude certain categories of employees from participating in any offering to the extent permitted by Section 423 of the Code, including employees who have not completed a minimum period of service with the Company and/or highly compensated employees. An employee may be excluded from participation in the ESPP if his or her participation in the ESPP is prohibited by local law or if complying with local law would cause the ESPP or an offering to violate the requirements of Section 423 of the Code. Also, in accordance with Section 423 of the Code, no employee may be granted a right to purchase shares of the Company's common stock under the ESPP if, immediately after such grant, such employee would own stock and/or hold outstanding options to purchase stock possessing 5% or more of the total combined voting power or value of all classes of stock of the Company or any subsidiary (including in such calculation stock held directly or indirectly by or for the benefit of the employee and stock held by certain persons related to the employee) or if such option would permit his or her rights to purchase stock under all employee stock purchase plans of the Company and its subsidiaries to accrue at a rate that exceeds $25,000 of the fair market value of such stock (determined at the time the option is granted) for each calendar year in which such option is outstanding at any time.

Participation. The ESPP permits an eligible employee to purchase shares of the Company's common stock through payroll deductions, which may not exceed 10% of the employee's eligible compensation (or such lesser or greater limit as may be determined by the Committee for a particular offering). Employees may withdraw all, but not less than all, of their accumulated payroll deductions prior to the end of an offering in accordance with the terms of the offering. Participation in the ESPP will end automatically upon termination of employment. In the event of withdrawal or termination of participation in the ESPP, a participant's accumulated payroll contributions will be refunded without interest.

Certain limitations on the number of shares of our common stock that a participant may purchase apply. For example, if an offering is over-subscribed whereby, when added together, the total number of shares of our common stock purchased by all participants in a given offering would exceed the total number of shares of our common stock remaining available under the ESPP, the Committee shall allocate such shares remaining available under the ESPP in as uniform a manner as practicable and as the Committee determines to be equitable.

Offerings; Purchase Price. The ESPP will be implemented through a series of offerings of up to a period of 27 months, which will consist of one offering period. During the offering period, payroll contributions will accumulate without interest and, on the last trading day of the offering period, accumulated payroll deductions will be used to purchase shares of our common stock.

The purchase price for each offering will be established by the Committee and may not be less than 85% of the fair market value of a share of our common stock on either the first trading day of an offering or on the purchase date, whichever is lower.

Adjustments. In the event that there occurs a change in our capital structure through such actions as an extraordinary cash or a stock dividend, a stock split, combination of shares or recapitalization, or a merger, consolidation, spin-off, split-off, spin-out, split-up, reorganization, partial or complete liquidation or other distribution of assets, issuance of rights or warrants to purchase securities, or any other corporate transaction or event having a similar effect, then in order to prevent dilution or enlargement of the benefits or potential benefits intended to be made available under the ESPP, the Committee will adjust (1) the number of shares reserved under the ESPP, (2) the number of shares by which the share reserve may increase automatically each year, (3) the purchase price of outstanding options and (4) the number of shares that are subject to purchase limits under an ongoing offering.

Dissolution or Liquidation. In the event of a proposed dissolution or liquidation of the Company, any offering then in progress will be shortened by setting a new purchase date before the proposed dissolution or liquidation and the offering will end immediately prior to the proposed dissolution or liquidation.

Change in Control. Unless otherwise determined by the Committee, in the event of a change in control (as defined in the ESPP) each outstanding option under the ESPP will be assumed or an equivalent option will be substituted by the successor corporation (or a parent or subsidiary of such successor corporation) and if the successor corporation refused to assume or substitute the options, then, unless otherwise provided by the Committee, the offering with respect to which the option relates will be shortened by setting a new purchase date, that will occur before the date of the change in control, on which the offering will end.

ESPP Amendment or Termination. The board of directors has the authority to amend or terminate the ESPP at any time. If any offering is terminated before its scheduled expiration, all amounts that have not been used to purchase shares of our common stock will be returned to participants (without interest, except as otherwise required by applicable law) as soon as administratively practicable. Unless earlier terminated by the board of directors, the ESPP shall have a term of 10 years.

Recovery of Erroneously Awarded Compensation

In September 2023, the board of directors approved a policy for the recovery of erroneously awarded compensation, or "clawback" policy, applicable to executive officers, which will become effective upon the consummation of this offering. The policy implements the incentive-based compensation recovery provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 as required under the listing standards of the New York Stock Exchange, and requires recovery of incentive-based compensation received after the effectiveness of the policy by current or former executive officers during the three fiscal years preceding the date it is determined that the Company is required to prepare an accounting restatement, including to correct an error that would result in a material misstatement if the error were corrected in the current period or left uncorrected in the current period. The amount required to be recovered is the excess of the amount of incentive-based compensation received over the amount that otherwise would have been received had it been determined based on the restated financial measure.

Director Compensation

Name[(1)]	2023 Fees earned or paid in cash ($)[(2)(3)]	Total ($)
Chanin Vongkusolkit	—	—
Somruedee Chaimongkol	—	—
Joseph R. Davis	266,795	266,795
Akaraphong Dayananda	—	—
Kirana Limpaphayom	—	—
Carla S. Mashinski	261,795	261,795
Thiti Mekavichai	—	—
Charles C. Miller III	271,795	271,795
Sunit S. Patel	261,795	261,795
Anon Sirisaengtaksin	—	—
Sinon Vongkusolkit	—	—

(1) Mr. Limpaphayom was elected to our board of directors effective September 12, 2023.

(2) Messrs. Davis, Miller and Patel and Ms. Mashinski received cash retainers pursuant to the Non-Employee Director Compensation Program, described below. Messrs. Davis, Miller and Patel and Ms. Mashinski earned annual cash retainers for 2023 equal to $80,000, $85,000, $75,000 and $75,000, respectively. For Messrs. Davis and Miller, the cash retainers paid pursuant to the Non-Employee Director Compensation Program included fees earned for their services on the Compensation Committee (for Mr. Davis) and the Audit & Risks Committee (for Mr. Miller).

(3) As described below, until the 2022 Plan becomes effective, the grant date value of RSU awards contemplated by our Non-Employee Director Compensation Program are to be paid in cash. Included in this column is (i) $110,082, which represents the cash payment made in June 2023 in lieu of the initial RSUs that would have been granted upon the effectiveness of the 2022 Plan for the non-employee director's services from the September 1, 2022 adoption of the Non-Employee Director Compensation Plan through the 2023 annual meeting of the Company's stockholders (the "2023 meeting") (of which, $46,411 would have related to services provided from the adoption of the Non-Employee Director Compensation Program through December 31, 2022 and $63,671 would have related to services provided from January 1, 2023 through the 2023 meeting) and (ii) $76,713, which represents

the portion of the cash payment in lieu of the RSUs that would have been granted at the 2023 meeting for service through the next annual meeting of the Company's stockholders that is attributable to services performed from the 2023 meeting through December 31, 2023. Because of the timing of the $110,082 cash payment in lieu of the initial RSU grant and its inclusion in this table, the amount paid to Messrs. Davis, Miller and Patel and Ms. Mashinski in 2023 appears higher than the annual compensation we pay our directors under the Non-Employee Director Compensation Plan.

Our board of directors adopted the BKV Corporation Non-Employee Director Compensation Program (the "Non-Employee Director Compensation Program"), pursuant to which our non-employee directors have been compensated as follows:

- Each non-employee director, other than a non-employee director who serves as chairman of the board, is entitled to receive an annual cash retainer of $75,000, and any non-employee director serving as the chairman of the board is entitled to receive an annual cash retainer of $137,500, each paid in quarterly installments, based on calendar quarters, in arrears on a prorated basis;
- Members of our Audit & Risks Committee (other than the chairperson thereof) are entitled to receive an additional cash retainer of $10,000, and the chairperson of the Audit & Risks Committee is entitled to receive an additional cash retainer of $20,000, each paid in quarterly installments, based on calendar quarters, in arrears on a prorated basis;
- Members of our Compensation Committee and Governance Committee (other than the chairpersons thereof) are entitled to receive an additional cash retainer of $5,000, and the chairperson of the Compensation Committee and chairperson of the Governance Committee are entitled to receive an additional cash retainer of $15,000, each paid in quarterly installments, based on calendar quarters, in arrears on a prorated basis;
- Each non-employee director who is re-elected to serve, or will continue serving as a non-employee director immediately following any annual meeting of the Company's stockholders, will receive an annual grant of RSUs on the date of the Company's annual shareholder meeting with a grant date value of $140,000, if such non-employee director will not serve as the chairman of the board, or $202,500, if such non-employee director will serve as the chairman of the board, which will vest on the day prior to the first annual meeting of the Company's stockholders following the date the RSUs are granted, subject to the non-employee director's continued service; and
- Each non-employee director will be reimbursed for reasonable out-of-pocket expenses incurred while attending meetings of the board or any of its committees.

Until the 2022 Plan becomes effective, cash has been and will be paid quarterly in arrears in lieu of the RSU awards. Messrs. C. Vongkusolkit, Dayananda, Limpaphayom, Mekavichai, Sirisaengtaksin and S. Vongkusolkit and Ms. Chaimongkol have waived their participation in the Non-Employee Director Compensation Plan, and therefore will not receive any compensation payable thereunder.

PRINCIPAL STOCKHOLDERS

The following table sets forth certain information regarding the beneficial ownership of our common stock immediately following the completion of this offering by (i) each NEO and director of the Company, (ii) all executive officers and directors of the Company as a group and (iii) each person known to the Company to own beneficially more than 5% of any class of our voting securities. Except as otherwise indicated, (a) the persons or entities identified in the table have sole voting and investment power with respect to all shares shown as beneficially owned by them and (b) the current directors and executive officers have not pledged any of such shares as security. All information with respect to beneficial ownership has been furnished by the respective 5% or more stockholders, directors or executive officers, as the case may be.

The following information has been presented in accordance with the SEC's rules and is not necessarily indicative of beneficial ownership for any other purpose. Under the SEC's rules, beneficial ownership of a class of capital stock as of any date includes any shares of that class as to which a person, directly or indirectly, has or shares voting power or investment power as of that date and also any shares as to which a person has the right to acquire sole or shared voting or investment power as of or within 60 days after that date through the exercise of any stock option, warrant or other right (including any conversion or redemption right).

We have based our calculation of the percentage of beneficial ownership prior to this offering on 70,515,337 shares of our common stock outstanding, which amount includes 4,161,792 shares of common stock underlying restricted stock units eligible for settlement as of the date of this prospectus. We have based our calculation of the percentage of beneficial ownership after this offering on shares of our common stock outstanding immediately following the completion of this offering, assuming that the underwriters do not exercise their option to purchase additional shares.

Unless otherwise indicated, the address of each beneficial owner listed in the table below is c/o BKV Corporation, 1200 17th Street, Suite 2100, Denver, Colorado 80202.

We expect each of the following to purchase shares under the reserved share program:
(shares).

The table does not reflect any shares of common stock that directors and executive officers may purchase through the reserved share program.

Name of Beneficial Owner	Beneficial Ownership Before the Offering: Common Stock Shares	%	Total Voting Power Before the Offering %	Beneficial Ownership After the Offering: Common Stock Shares	%	Total Voting Power After the Offering %
Named Executive Officers and Directors:						
Christopher P. Kalnin	2,518,549(1)	3.6%	3.6%			
John T. Jimenez	358,841(2)	*	*			
Eric S. Jacobsen	435,083(3)	*	*			
Barry S. Turcotte	—	—%	—%			
Somruedee Chaimongkol	—	—%	—%			
Joseph R. Davis	23,000	*	*			
Akaraphong Dayananda	—	—%	—%			
Kirana Limpaphayom	—	—%	—%			
Carla S. Mashinski	—	—%	—%			
Thiti Mekavichai	18,500	*	*			
Charles C. Miller III	87,500	*	*			
Sunit S. Patel	—	—%	—%			
Anon Sirisaengtaksin	—	—%	—%			
Chanin Vongkusolkit	—	—%	—%			
Sinon Vongkusolkit	—	—%	—%			
All executive officers and directors as a group (16 persons)	4,103,288	5.8%	5.8%			
5% Stockholders:						
Banpu North America Corporation(4)	63,877,614	90.6%	90.6%			

* Less than 1%.

(1) Includes 48,885 shares of our common stock underlying outstanding TRSUs that vested on January 1, 2024 and 674,091 shares of our common stock underlying PRSUs for which the Compensation Committee determined performance achievement on February 8, 2024, but, in each case, have not been settled as of the date of this prospectus, and 875,754 shares of our common stock held by Mr. Kalnin's spouse. In addition, Mr. Kalnin will receive 73,328 shares of our common stock underlying outstanding TRSUs that will vest upon consummation of this offering.

(2) Includes 17,381 shares of our common stock underlying outstanding TRSUs that vested on April 16, 2024 and 319,567 shares of our common stock underlying PRSUs for which the Compensation Committee determined performance achievement on February 8, 2024, but, in each case, have not been settled as of the date of this prospectus. In addition, Mr. Jimenez will receive 17,381 shares of our common stock underlying outstanding TRSUs that will vest upon consummation of this offering.

(3) Includes 27,748 shares of our common stock underlying outstanding TRSUs that vested on January 1, 2024 and 382,653 shares of our common stock underlying PRSUs for which the Compensation Committee determined achievement on February 8, 2024, but, in each case, have not been settled as of the date of this prospectus. In addition, Mr. Jacobsen will receive 41,626 shares of our common stock underlying outstanding TRSUs that will vest upon consummation of this offering.

(4) Approximately 90.6% of our outstanding shares of common stock are currently owned by BNAC, a Delaware corporation wholly owned by BOG Co., Ltd., a wholly owned subsidiary of Banpu, a public company listed on the Stock Exchange of Thailand and the ultimate parent company of BKV Corporation, BNAC, Banpu Power and BPPUS. The principal address of Banpu is 27th Floor, Thanapoom Tower, 1550 New Petchburi Road, Makkasan, Ratchathewi, Bangkok, Thailand.

CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

We describe below transactions and series of similar transactions, during our last three fiscal years or currently proposed, to which we were a party or will be a party, in which:

- the amounts involved exceeded or will exceed $120,000; and
- any of our directors, director nominees, executive officers or beneficial holders of more than 5% of any class of our voting securities, or any immediate family member of any such person, had, or will have, a direct or indirect material interest.

Other than as described below, there have not been, nor are there any currently proposed, transactions or series of similar transactions meeting these criteria to which we have been or will be a party other than compensation arrangements, which are described where required under "*Executive Compensation.*"

Stockholders' Agreement

We are party to a stockholders' agreement, dated as of May 1, 2020, with certain of our stockholders, including BNAC and Chris Kalnin. Our existing stockholders' agreement will be terminated prior to the completion of this offering.

Additionally, in connection with the closing of this offering, we will enter into our Stockholders' Agreement with BNAC. Pursuant to our Stockholders' Agreement, for so long as BNAC and Banpu beneficially own 10% or more of our voting stock, BNAC will be entitled to designate for nomination to our board of directors a number of individuals approximately proportionate to such beneficial ownership, provided that (i) from the completion of this offering until the first anniversary of the completion of this offering, at least three board seats will not be BNAC designees, (ii) from and after the first anniversary of the completion of this offering until the first date on which BNAC and Banpu beneficially own 50% or less of our voting stock, at least four board seats will not be BNAC designees, and (iii) from and after the first date on which BNAC and Banpu beneficially own 50% or less of our voting stock, a number of board seats equal to the minimum number of directors that would constitute a majority of the total number of directors comprising our board of directors will not be BNAC designees. Under our Stockholders' Agreement, we will agree to use our best efforts to cause the election of the individuals nominated by BNAC to our board of directors, including nominating such individuals to be elected as a director, recommending their election and soliciting proxies or consents in favor of their election. Our Stockholders' Agreement also provides that we and BNAC shall, to the extent permitted by law, take actions to cause our Chief Executive Officer to be included in our board of directors.

In addition, for so long as BNAC and its affiliates beneficially own shares of our voting stock representing at least 25% of our total voting power, BNAC will have the right to designate the chairman of our board of directors from among its designees. Our Stockholders' Agreement will also provide BNAC with certain information rights for so long as it continues to own shares of our voting stock representing at least 25% of our voting power. Further, we may not amend our charter or our bylaws in a manner inconsistent with the rights granted to BNAC pursuant to our Stockholders' Agreement without BNAC's consent.

Our Stockholders' Agreement will terminate on the earlier to occur of (i) such time as BNAC is no longer entitled to designate a director pursuant to our Stockholders' Agreement (except that the registration rights discussed below will survive and continue until BNAC and its affiliates no longer hold any shares of our common stock constituting registrable securities (as defined in our Stockholders' Agreement)) and (ii) the delivery of written notice by BNAC to us requesting termination of our Stockholders' Agreement.

Equity Investments and Preemptive Rights Offering

The following share numbers have not been adjusted to give effect to our one-for-two reverse stock split that occurred on October 30, 2023.

On October 1, 2020, we issued 22,284,000 shares of BKV common stock to BNAC, an existing shareholder, for $222.8 million.

Additionally, in order to fund the Debt Service Reserve Account in the amount of $138.3 million pursuant to the requirements of the Term Loan Credit Agreement, BKV made a capital call on BNAC of $150.0 million and, pursuant to the requirements of the existing stockholders' agreement, on September 27, 2023, BNAC made such capital contribution by purchasing 15,000,000 shares of BKV common stock. Subsequently, on September 29, 2023, pursuant to the preemptive rights provision contained in Article VI, Section 5 of the Company's existing bylaws, as amended and restated, we issued 521 shares of BKV common stock for $5,210, in the aggregate, to certain existing stockholders that qualified as "accredited investors" within the meaning of Rule 501(a) of Regulation D promulgated under the Securities Act.

BKV-BPP Power Joint Venture

BKV-BPP Power is jointly controlled by us and BPPUS through a board of directors consisting of eight members, four of whom are appointed by us and four of whom are appointed by BPPUS. We account for BKV-BPP Power using the equity method of accounting.

In November 2021, BKV-BPP Power acquired Temple I for an aggregate purchase price of $430.0 million. BKV-BPP Power was formed in July 2021 for the purpose of purchasing and operating Temple I and is a joint venture owned 50% by us and 50% by BPPUS, a wholly owned subsidiary of Banpu Power.

In connection with the purchase of Temple I, we made a capital contribution to BKV-BPP Power in the amount of $87.0 million and BPPUS made a capital contribution to BKV-BPP Power in the amount of $87.0 million.

In July 2023, BKV-BPP Power acquired Temple II for an aggregate purchase price of $460.0 million. In connection with the purchase of Temple II, a subsidiary of BKV-BPP Power entered into the Temple II Credit Agreement. For more information about the Temple II Credit Agreement, see "*Business — Our Operations — Power Generation —Temple II Acquisition Financing*."

Temple I Loan Agreements

On October 14, 2021, BKV-BPP Power entered into a Loan Agreement (the "$141 Million Banpu Loan Agreement") with BNAC, which allowed for a single drawdown in the amount of $141.0 million. On November 1, 2021, BKV-BPP Power borrowed $141.0 million for the purpose of acquiring Temple I and working capital.

On October 15, 2021, BKV-BPP Power entered into a Loan Agreement (the "141 Million BPPUS Loan Agreement" and, together with the $141 Million Banpu Loan Agreement, the "Temple I Loan Agreements") with BPPUS, which allowed for a single drawdown in the amount of $141.0 million. On November 21, 2021, BKV-BPP Power borrowed $141.0 million for the purpose of acquiring Temple I and working capital.

BKV-BPP Power's payment obligations under the Temple I Loan Agreements are senior unsecured indebtedness. The Temple I Loan Agreements bear interest at 12-month SOFR plus 4.6% per annum. Interest on the loans is payable on a semi-annual basis, and the loans will mature on November 1, 2023. BKV-BPP is permitted to prepay the loans at any time, with no prepayment premium. The Temple I Loan Agreements include covenants that, among other things, prohibit BKV-BPP from merging, incurring liens or incurring any additional indebtedness or guarantees. The Temple I Loan Agreements include financial covenants that require BKV-BPP Power to maintain a minimum net worth (as defined in the Temple I Loan Agreements, but generally meaning total assets minus total liabilities). In the $141 Million Banpu Loan Agreement, the minimum net worth requirement is $120.0 million and in the $141 Million BPPUS Loan Agreement, the minimum net worth requirement is $40.0 million. Under the Temple I Loan Agreements, BNAC and BPPUS have no recourse to us with respect to any amounts owed to them thereunder and we are not liable in any manner (and are not required to provide security) for any obligations owed to them thereunder.

BKV-BPP Power Limited Liability Company Agreement

We and BPPUS are each a party to the BKV-BPP Power LLC Agreement governing the BKV-BPP Power Joint Venture, which, among other things, provides that a general manager appointed by the Power JV

Board will have the power to manage and administer the business and affairs of BKV-BPP Power, subject to specified matters reserved for approval by the Power JV Board. The appointment and removal of the general manager must be approved by both the Power JV Board and BPPUS. Transfer or encumbrance of a party's interest in BKV-BPP Power is permitted without prior approval of the other party or the Power JV Board. However, no transfer will be permitted if the transfer: (A) would subject BKV-BPP Power to U.S. federal securities law reporting requirements, (B) would cause BKV-BPP Power to lose its status as a U.S. partnership for federal income tax purposes or will cause BKV-BPP Power to be classified as a "publicly traded partnership," (C) would violate, give rise to a default under or cause any payment to become due under any credit agreement, guaranty, or similar credit document or any other material contract to which BKV-BPP Power or any affiliate is bound, or (D) occurs prior to the repayment by BKV-BPP Power of all loans and other amounts outstanding under the term loans.

In the event that either party admits in writing that it is unable to perform its obligations (including any obligation to provide additional capital contributions) under the BKV-BPP Power LLC Agreement, the non-defaulting party will be entitled to (i) sell the assets of the joint venture and dissolve the joint venture on reasonable terms deemed acceptable to the Power JV Board, (ii) obtain specific performance of the non-defaulting party's obligations and/or (iii) exercise any other right or remedy provided in law or in equity.

The Power JV Board will determine the amount and timing of distributions of operating cash flow (which will be done no less frequently than once per quarter) and net capital proceeds (which will be distributed within three business days after becoming available for distribution). All distributions will be made on a pro-rata basis to us and BPPUS. During the year ended December 31, 2023, BKV-BPP Power made a distribution to BKV Corp and BPPUS of $10.0 million to each member. For the six months ended June 30, 2024 and 2023 and for the years ended December 31, 2022 and 2021, no distributions were made by BKV-BPP Power or BKV-BPP Cotton Cove.

Additional cash capital contributions will be required to be made by us and by BPPUS on a pro-rata basis upon 30 days written notice either by us or by BPPUS; provided that the additional contributions must be expended on items included in the annual approved budget, items in response to an emergency in the event that BKV-BPP Power does not have sufficient cash reserves to address such emergency, or any other matter approved by the Power JV Board. Otherwise, neither us nor BPPUS will be required to provide additional capital contributions without consent.

Major decisions and significant activities of BKV-BPP Power are reserved for approval by at least a majority of the members of the Power JV Board, such as, among other things, any merger, consolidation, amalgamation, conversion of BKV-BPP Power or any of its subsidiaries, into another form or entity or other business combination of any nature, wind up, the dissolution, liquidation, commencement or any filing or petition for a voluntary bankruptcy, reorganization, debt arrangement involving BKV-BPP Power, any plan to or initial sale of BKV-BPP Power or other equity interests to the public, any amendments, restatements or revocations of its organizational documents, execution, amendment or termination of a material contract, and any amendment to or deviation from the dividend policy of the joint venture or any of its subsidiaries. Under the terms of the BKV-BPP Power LLC Agreement:

- we do not have the power to unilaterally cause BKV-BPP Power to make distributions;
- we may be required to make additional capital contributions to fund items approved in the annual budget or other matters approved by the board of BKV-BPP Power at the request of BPPUS, which would reduce the amount of cash otherwise available to us or require us to incur additional indebtedness; and
- BKV-BPP Power may incur additional indebtedness in an amount greater than $1,500,000 if approved by the board of BKV-BPP Power, which debt payments would reduce the amount of cash that might otherwise be available for distributions to us.

In December 2021, we entered into an Administrative Service Agreement (as amended on December 1, 2022, the "BKV-BPP Power Administrative Services Agreement") with BKV-BPP Power. Under the Administrative Service Agreement, we provide certain operational, accounting, tax and other services as required by the BKV-BPP Power Administrative Services Agreement and in return receive an annual fee of $2.65 million until December 1, 2023, with options to extend. In addition to the annual fee, we are entitled to receive reimbursement for all (i) reasonable, ordinary and necessary out-of-pocket expenses actually incurred in connection with travel, (ii) actual costs of audits, legal fees, tax return preparations and other third-party professional fees approved by BKV-BPP Power and (iii) reasonable, ordinary and necessary out-of-pocket expenses actually incurred by us in connection with the services provided by us under the BKV-BPP Power Administrative Services Agreement. During the six months ended June 30, 2024 and 2023, and years ended December 31, 2023, 2022 and 2021, we recognized \$2.2 million, \$1.3 million, \$3.6 million, \$2.7 million and \$0.2 million, respectively, of revenues related to the services provided under the BKV-BPP Power Administrative Services Agreement.

BKV-BPP Cotton Cove Joint Venture

BKV-BPP Cotton Cove is a joint venture owned 51% by BKV dCarbon Ventures and 49% by BPPUS and formed on August 25, 2023 to own the Cotton Cove Project. BKV-BPP Cotton Cove is jointly controlled by BKV dCarbon Ventures and BPPUS through a board of managers consisting of six members, four of whom are appointed by BKV dCarbon Ventures and two of whom are appointed by BPPUS. As discussed below, any environmental attributes arising from the Cotton Cove Project will be distributed and allocated to BKV dCarbon Ventures on an annual basis.

We currently expect the total investment required for the Cotton Cove Project to be approximately \$17.6 million. To fund such investment, and pursuant to the terms of the BKV-BPP Cotton Cove LLC Agreement, BKV dCarbon Ventures will make a capital contribution to BKV-BPP Cotton Cove in the amount of \$9.0 million and BPPUS will make a capital contribution to BKV-BPP Cotton Cove in the amount of \$8.6 million.

BKV-BPP Cotton Cove Limited Liability Company Agreement

BKV dCarbon Ventures and BPPUS are each a party to the BKV-BPP Cotton Cove LLC Agreement governing the BKV-BPP Cotton Cove Joint Venture, which, among other things, provides that:

- any environmental attributes arising from the Cotton Cove Project will be distributed and allocated to BKV dCarbon Ventures on an annual basis;
- BKV dCarbon Ventures has the power to manage and administer the business and affairs of BKV-BPP Cotton Cove, subject to specified matters reserved for approval by the Cotton Cove JV Board, as discussed below;
- BKV dCarbon Ventures has agreed to enter into an administrative services agreement and management agreement with BKV-BPP Cotton Cove; and
- BKV-BPP Cotton Cove has agreed to reimburse BKV dCarbon Ventures in an amount equal to 100% of the costs and expenses incurred and paid by BKV dCarbon Ventures for subsurface seismic testing intended to determine the optimal location and design for the Cotton Cove Project.

Additionally, neither party can transfer or encumber its interests in BKV-BPP Cotton Cove, except transfers to its affiliates, without prior approval of the Cotton Cove JV Board, and no transfer will be permitted if the transfer would, among other things, (i) violate, give rise to a default under or cause any payment to become due under any credit agreement, guaranty, or similar credit document or any other material contract to which BKV-BPP Cotton Cove or any affiliate is bound or (ii) cause any of BKV-BPP Cotton Cove, BKV dCarbon Ventures or BPPUS to suffer any reduction in entitlement to, or recapture of tax credits under Section 45Q of the Code or any monetization of such tax credits under Section 6417 or Section 6418 of the Code.

In the event that either party admits in writing that it is unable to perform its obligations (including any obligation to provide additional capital contributions) under the BKV-BPP Cotton Cove LLC Agreement, the non-defaulting party will be entitled to (i) sell the assets of the joint venture and dissolve the joint venture on reasonable terms deemed acceptable to the Cotton Cove JV Board, (ii) obtain specific performance of the non-defaulting party's obligations and/or (iii) exercise any other right or remedy provided in law or in equity.

The Cotton Cove JV Board will determine the amount and timing of distributions of operating cash flow and net capital proceeds (which will be distributed within three business days after becoming available for distribution). All distributions will be made on a pro-rata basis to BKV dCarbon Ventures and BPPUS. As of December 31, 2023, no distributions have been made by BKV-BPP Cotton Cove. Additional cash capital contributions in amounts of up to approximately $1.4 million and $1.7 million may be required to be made by BKV dCarbon Ventures and by BPPUS, respectively, upon receipt of a unanimous request from the Cotton Cove JV Board; provided that (i) BKV-BPP Cotton Cove LLC Agreement prohibits the Cotton Cove JV Board from making any such request to BPPUS unless and until BKV dCarbon Ventures has made its initial capital contribution in full and (ii) any such additional contributions made by BPPUS must be expended on items included in the annual approved budget, items in response to an emergency in the event that BKV-BPP Cotton Cove does not have sufficient cash reserves to address such emergency, or any other matter approved by the Cotton Cove JV Board.

The BKV-BPP Cotton Cove LLC Agreement delegates to BKV dCarbon Ventures full authority to decide, agree, consent to, approve, perform, enter into, delegate or otherwise undertake any activity that does not (A) violate applicable law for and on behalf BKV-BPP Cotton Cove or (B) qualify as a major decision or significant activity of BKV-BPP Cotton Cove that requires the unanimous consent of the Cotton Cove JV Board, such as, among other things: (i) making certain elections available to BKV-BPP Cotton Cove with respect to the monetization of Section 45Q credits; (ii) approving certain final investment decisions related to the Cotton Cove Project; (iii) directing transfers of BKV-BPP Cotton Cove membership interests to unaffiliated third parties; (iv) entering into any merger, consolidation, amalgamation, conversion of BKV-BPP Cotton Cove or any of its subsidiaries, into another form or entity or any other business combination of any nature; (v) causing the wind up, dissolution, liquidation, commencement or any filing or petition for a voluntary bankruptcy, reorganization, debt arrangement involving BKV-BPP Cotton Cove; (vi) authorizing any amendment, restatement or revocation of the organizational documents of BKV-BPP Cotton Cove or its subsidiaries; (vii) authorizing increases or decrease of the required capital contributions; (viii) determining the location of the wells associated with the Cotton Cove Project; or (ix) decisions related a possible initial public offering of BKV-BPP Cotton Cove. Under the terms of the BKV-BPP Cotton Cove LLC Agreement:

- BKV dCarbon Ventures does not have the power to unilaterally cause BKV-BPP Cotton Cove to make distributions; and
- a majority of the Cotton Cove JV Board may require BKV dCarbon Ventures to make additional capital contributions to fund items approved in the annual budget or other matters approved by the Cotton Cove JV Board, which would reduce the amount of cash otherwise available to BKV dCarbon Ventures or require BKV dCarbon Ventures to incur additional indebtedness.

Loan Agreements

Intercompany Loan Agreements

On December 17, 2019, BKV O&G entered into the $10 Million Loan Agreement with BNAC, which allowed for a single drawdown in the amount of $10.0 million. On June 23, 2020, we entered into a novation agreement with BKV O&G and BNAC, which transferred all of BKV O&G’s rights and obligations under the $10 Million Loan Agreement to us. Also on June 23, 2020, we entered into the First Amendment to the Loan Agreement. On July 1, 2020, we borrowed $10.0 million thereunder for working capital purposes. During the year ended December 31, 2020, we paid $0.2 million in interest on the loan, and on December 31, 2020, we repaid $5.0 million of the outstanding principal amount of the loan. During the year ended December 31, 2021, we paid $0.1 million in interest on the loan and repaid the remaining outstanding principal amount of the loan in full. The First Amendment to $10 Million Loan Agreement terminated on June 20, 2021.

On September 28, 2020, we borrowed $119.0 million under the $119 Million Loan Agreement with BNAC to partially fund the Devon Barnett Acquisition and for working capital. During the year ended December 31, 2020, we paid $1.5 million in interest on the loan, and on December 16, 2020, we repaid $100.0 million of the outstanding principal amount of the loan. During the year ended December 31, 2021, we paid $0.2 million in interest on the loan, and on March 15, 2021, we repaid the remaining outstanding principal amount of the loan in full. The $119 Million Loan Agreement terminated concurrently with repayment of the remaining principal amount.

On November 8, 2021, we borrowed $50.0 million under the $50 Million Loan Agreement with BNAC. On January 11, 2022, we repaid $15.0 million of the outstanding principal amount of the loan. On June 1, 2022, we paid $1.3 million in interest on the loan and repaid the remaining $35.0 million of the outstanding principal amount of the loan in full. The $50 Million Loan Agreement terminated concurrently with repayment of the remaining principal amount.

For additional information, see "*Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Loan Agreements and Credit Facilities — Intercompany Loan Agreements.*"

Subordinated Intercompany Loan Agreements

On October 14, 2021, we borrowed $116.0 million under the $116 Million Loan Agreement with BNAC to redeem all of the outstanding preferred and common stock of the company owned by OCM BKV Holdings, LLC, an affiliate of Oaktree Capital Management L.P. Following such redemption, we do not have any issued and outstanding preferred stock. On June 15, 2022, we entered into the $116 Million A&R Loan Agreement, which amended and restated the $116 Million Loan Agreement to, among other things, subordinate the $116.0 million term loan owed to BNAC thereunder to the term loans we borrowed under the Term Loan Credit Agreement. On August 24, 2022, BNAC entered into a Subordination Agreement with Bangkok Bank Public Company Limited, New York Branch, which subordinated the $116.0 million term loan owed to BNAC to the revolving loans at any time outstanding under the Revolving Credit Agreement (the "August 2022 Subordination Agreement"). On September 16, 2022, we repaid the full $116.0 million balance of the loan.

On March 10, 2022, we borrowed $75.0 million under the $75 Million Loan Agreement with BNAC to fund the deposit for the Exxon Barnett Acquisition. On June 15, 2022, we entered into the BNAC A&R Loan Agreement, which amended and restated the $75 Million Loan Agreement to, among other things, subordinate the $75.0 million term loan owed to BNAC thereunder to the term loans we borrowed under the Term Loan Credit Agreement. The August 2022 Subordination Agreement provides for the subordination of the $75.0 million term loan owed to BNAC thereunder to the revolving loans at any time outstanding under the Revolving Credit Agreement. In connection with entering into the RBL Credit Agreement, our obligations under the BNAC A&R Loan Agreement were subordinated to our obligations under the RBL Credit Agreement. On June 18, 2024, we paid down $25.0 million of the $75.0 million, including interest.

For additional information, see "*Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Loan Agreements and Credit Facilities — Subordinated Intercompany Loan Agreements*."

Tax Sharing Agreement

Since our inception, BNAC has owned, directly and indirectly, in excess of 80% of the outstanding shares of our common stock, with the result that we have been included in BNAC's consolidated federal income tax group (as well as in certain consolidated, combined and unitary state and local income tax returns filed by BNAC). If and when BNAC's ownership of our common stock falls below 80%, we will cease to be part of BNAC's consolidated federal income tax group. We are party to a Tax Sharing Agreement, dated as of May 1, 2020 (the "Existing Tax Sharing Agreement"), with BNAC, providing for payment by us to BNAC of the amounts payable by us in respect of U.S. federal income taxes and certain state and local taxes, and for certain payments by BNAC to us. We made no payments to BNAC under the Existing Tax Sharing Agreement in 2020, 2021 and 2022.

At the completion of this offering, we anticipate BNAC will own less than 80% of the outstanding shares of our common stock and, as a result, we will generally be deconsolidated from BNAC for federal and, in most cases, state, income tax purposes for periods beginning after completion of the offering. In anticipation of this offering, we will enter into an Amended and Restated Tax Sharing Agreement with BNAC, which sets forth the principles and responsibilities (i) governing the allocation of consolidated U.S.

federal income tax liabilities and consolidated, combined and unitary state and local income tax liabilities between us and BNAC during the periods in which we have been and are included in any consolidated or combined income tax return filed by BNAC, (ii) specifying the allocation of tax attributes and tax liabilities in connection with deconsolidation and (iii) setting forth agreements with respect to certain other tax matters.

The Amended and Restated Tax Sharing Agreement contains provisions that we believe are customary for tax sharing agreements between members of a consolidated group. In particular, we make payments to BNAC in respect of our allocable share of the U.S. federal income consolidated tax liability and state and local combined tax liability, in each case as determined on a separate return basis. In addition, we are compensated for the use of our net operating losses and other tax assets to the extent such assets reduce the U.S. federal income consolidated tax liability or state and local combined tax liability, as applicable, during the periods in which we have been and are included in any consolidated or combined income tax return filed by BNAC. The Amended and Restated Tax Sharing Agreement also includes customary indemnification clauses and survives until all obligations and liabilities of the parties arising under the agreement are satisfied.

Registration Rights

Our Stockholders' Agreement will provide BNAC and its affiliates with the right, in certain circumstances, to require us to register their shares of our common stock constituting registrable securities under the Securities Act for sale into the public markets and with certain piggyback rights, as described below. Our Stockholders' Agreement will also provide that we will pay certain expenses of BNAC and its affiliates relating to such registrations and indemnify them against certain liabilities that may arise under the Securities Act.

Demand Rights/Shelf Registration Rights

Subject to certain limitations, following the date that is six months after the consummation of this offering, BNAC and its affiliates will have the right, by delivering written notice to us, to require us to register the number of their registrable securities requested under the Securities Act. In no event later than 45 days after receiving a valid demand request, we are required to file or confidentially submit, at our discretion, with the SEC a registration statement covering all of the registrable securities covered by such demand request, subject to the limitations discussed below. We will not be obligated to effect more than two such registered offerings in any 12-month period.

Upon the delivery of written notice to us by BNAC and its affiliates from time to time after a shelf registration statement has been declared effective by the SEC, we will facilitate a takedown of registrable securities off of an effective shelf registration statement. We will not be required to effect (i) an underwritten shelf takedown unless the offering includes securities with a total offering price (including piggyback securities and before deducting underwriting discounts) reasonably expected to exceed, in the aggregate, $5.0 million and (ii) more than two offerings demanded pursuant to this paragraph or the preceding paragraph in any 12-month period.

In addition, if we are eligible to file a shelf registration statement on Form S-3, BNAC and its affiliates can request that we register their registrable securities for resale on a shelf registration statement.

Piggyback Rights

BNAC and its affiliates will be entitled to request to participate in, or "piggyback" on, registrations of common stock for sale by us or underwritten shelf takedowns. This piggyback right does not apply to, among other things, a registration relating to our employee benefit plans, a registration on Form S-4 or Form S-8 (or any similar successor forms) or a registration where the registrable securities are not being sold for cash.

Conditions and Limitations

The rights outlined above will be subject to conditions and limitations, including the right of the underwriters to limit the number of shares of our common stock to be included in a registration statement and our right to postpone or suspend a registration statement under specified circumstances.

Indemnification Agreements with our Directors and Officers

We intend to enter into indemnification agreements, to be effective upon the completion of this offering, with each of our directors and officers. The indemnification agreements and our governing documents will require us to indemnify our directors and officers to the fullest extent permitted by Delaware law. Subject to certain limitations, the indemnification agreements and our governing documents will also require us to advance expenses incurred by our directors and officers. For more information regarding these agreements, see "*Description of Capital Stock — Limitations of Liability and Indemnification*."

Employee Relationship with Chief Legal Officer

Tara Blevins, the sister of Lindsay B. Larrick, our Chief Legal Officer, is employed by the Company in a non-executive officer position and received total compensation of approximately $161,000, $266,000 and $281,000 in 2021, 2022 and 2023, respectively. Her compensation was established by the Company in accordance with its compensation practices applicable to employees with comparable qualifications and responsibilities and holding similar positions.

Independent Contractor Relationship with Chief Executive Officer and Director

Rebecca Kalnin, the spouse of Christopher P. Kalnin, our Chief Executive Officer and a director of the Company, is engaged as an independent contractor, through Wood Group PSN, Inc., a third-party consulting firm, as a Human Resources Advisor to the Company. The Company made payments of approximately $148,000 and $57,500 in 2022 and 2023, respectively, to such firm for her services, and, in turn, such firm paid her less than $120,000 in each of 2022 and 2023.

Policies and Procedures Regarding Related Party Transactions

Upon completion of this offering, we expect that our board of directors will adopt a new written Code of Business Conduct and Ethics that complies with all applicable requirements of the SEC and NYSE and that contains conflict of interest policies governing transactions involving any director, executive officer or beneficial owner of more than 5% of any class of our voting securities that could be deemed to present a conflict of interest.

Upon completion of this offering, we expect that our board of directors will adopt a written related party transactions policy, pursuant to which our Audit & Risks Committee will be responsible for reviewing and either approving, ratifying or disapproving such transactions with our directors, officers or beneficial owners of more than 5% of any class of our voting securities, or any immediate family member of any of the foregoing persons. In considering a related party transaction, our Audit & Risks Committee will take into account relevant facts and circumstances relating to whether the transaction is in the best interests of the Company, including the following:

- the materiality of the transaction to the related party and the Company;
- the business purpose for and reasonableness of the transaction; and
- whether the transaction is comparable to a transaction that could be available with an unrelated party or is on terms that the Company offers generally to persons who are not related parties.

DESCRIPTION OF CAPITAL STOCK

General

The following description summarizes certain important terms of our capital stock and of our governing documents, as each will be in effect upon the completion of this offering. For a complete description of the matters set forth in this section titled "*Description of Capital Stock*," you should refer to our governing documents, which are included as exhibits to the registration statement of which this prospectus forms a part, and to the applicable provisions of Delaware law.

On October 30, 2023, we completed a one-for-two reverse stock split. As a result of the reverse stock split, every two shares of our outstanding common stock were combined into and now represent one share of common stock, and fractional shares were paid out in cash. Following the reverse stock split, our authorized capital stock consists of 300,000,000 shares of common stock, $0.01 par value per share, of which 66,353,545 shares are issued and outstanding as of the date of this prospectus, and 80,000,000 shares of preferred stock, $0.01 par value per share, of which no shares are issued and outstanding as of the date of this prospectus.

Upon completion of this offering, our authorized capital stock will consist of 500,000,000 shares of common stock, $0.01 par value per share, of which shares (or shares if the underwriters exercise in full their option to purchase additional shares) will be issued and outstanding, and 80,000,000 shares of preferred stock, $0.01 par value per share, of which no shares will be issued and outstanding. In addition, 5,000,000 shares of our common stock will be reserved for issuance pursuant to the 2022 Plan and 500,000 shares of common stock will be available for purchase by employees pursuant to the ESPP. See "*Executive Compensation — BKV Corporation 2022 Equity and Incentive Compensation Plan" and "Executive Compensation — BKV Corporation Employee Stock Purchase Plan*."

As of the date of this prospectus, BNAC owns approximately 90.6% of our common stock.

Common Stock

Holders of shares of our common stock are entitled to one vote for each share held of record on all matters on which stockholders are entitled to vote generally, including the election or removal of directors elected by our stockholders generally. Holders of our common stock do not have cumulative voting rights in the election of directors. Subject to certain nomination rights of BNAC under our Stockholders' Agreement, holders of our common stock will be entitled to elect all directors to our board of directors. See "*Certain Relationships and Related Party Transactions — Stockholders' Agreement*."

Holders of shares of our common stock are entitled to receive dividends when, as and if declared by our board of directors out of funds legally available therefor, subject to any statutory or contractual restrictions on the payment of dividends and to any restrictions on the payment of dividends imposed by the terms of any outstanding preferred stock. See "*Dividend Policy*."

Upon our liquidation, dissolution or winding up and after payment in full of all amounts required to be paid to creditors and to the holders of preferred stock having liquidation preferences, if any, the holders of shares of our common stock will be entitled to receive pro rata our remaining assets available for distribution.

All shares of our common stock that will be outstanding at the time of the completion of the offering will be fully paid and non-assessable. Our common stock will not be subject to further calls or assessments by us. Holders of shares of our common stock do not have preemptive, subscription, redemption or conversion rights. There will be no redemption or sinking fund provisions applicable to our common stock. The rights powers, preferences and privileges of our common stock will be subject to those of the holders of any shares of our preferred stock or any other series or class of stock we may authorize and issue in the future.

Preferred Stock

No shares of preferred stock will be issued or outstanding immediately after the offering contemplated by this prospectus. Our certificate of incorporation authorizes our board of directors to establish one or more series of preferred stock (including convertible preferred stock). Unless required by law or any stock exchange, the authorized shares of preferred stock will be available for issuance without further action by the holders of our common stock. Our board of directors is able to determine, with respect to any series of preferred stock, the powers (including voting powers), preferences and relative, participating, optional or other special rights, and the qualifications, limitations or restrictions thereof, including, without limitation:

- the designation of the series;
- the number of shares of the series, which our board of directors may, except where otherwise provided in the preferred stock designation, increase (but not above the total number of authorized shares of the class) or decrease (but not below the number of shares then outstanding);
- whether dividends, if any, will be cumulative or non-cumulative and the dividend rate of the series;
- the dates at which dividends, if any, will be payable;
- the redemption or repurchase rights and price or prices, if any, for shares of the series;
- the terms and amounts of any sinking fund provided for the purchase or redemption of shares of the series;
- the amounts payable on shares of the series in the event of any voluntary or involuntary liquidation, dissolution or winding-up of our affairs;
- whether the shares of the series will be convertible into shares of any other class or series, or any other security, of us or any other entity, and, if so, the specification of the other class or series or other security, the conversion price or prices or rate or rates, any rate adjustments, the date or dates as of which the shares will be convertible and all other terms and conditions upon which the conversion may be made;
- restrictions on the issuance of shares of the same series or of any other class or series; and
- the voting rights, if any, of the holders of the series.

Dividends

The DGCL permits a corporation to declare and pay dividends on shares of its capital stock out of “surplus” or, if there is no “surplus,” out of its net profits for the fiscal year in which the dividend is declared and/or the preceding fiscal year. “Surplus” is defined as the excess of the net assets of the corporation over the amount determined to be the capital of the corporation by its board of directors. The capital of the corporation is typically calculated to be (and cannot be less than) the aggregate par value of all issued shares of capital stock. Net assets equals the fair value of the total assets minus total liabilities. The DGCL also provides that dividends may not be paid out of net profits if, after the payment of the dividend, remaining capital would be less than the capital represented by the outstanding stock of all classes having a preference upon the distribution of assets. Declaration and payment of any dividend will be subject to the discretion of our board of directors. See “*Dividend Policy*.”

Annual Stockholder Meetings

Our bylaws provide that annual stockholder meetings will be held at a date, time and place, if any, as determined by our board of directors or a duly authorized committee thereof. To the extent permitted under applicable law, we may conduct meetings by remote communications, including by webcast.

Anti-Takeover Provisions

Our governing documents and the DGCL contain provisions, which are summarized in the following paragraphs, that are intended to enhance the likelihood of continuity and stability in the composition of our board of directors. These provisions are intended to avoid costly takeover battles, reduce our vulnerability to a hostile or abusive change of control and enhance the ability of our board of directors to maximize stockholder value in connection with any unsolicited offer to acquire us. However, these provisions may have an anti-takeover effect and may delay, deter or prevent a merger or acquisition of the Company by means of a tender offer, a proxy contest or other takeover attempt that a stockholder might consider in its best interest, including those attempts that might result in a premium over the prevailing market price for the shares of common stock held by stockholders.

Authorized but Unissued Capital Stock

Delaware law does not require stockholder approval for any issuance of shares that are authorized and available for issuance. However, the listing requirements of the NYSE, which would apply so long as our common stock remains listed on the NYSE, require stockholder approval of certain issuances equal to or exceeding 20% of the then outstanding voting power of our capital stock or then outstanding number of shares of common stock. These additional shares may be used for a variety of corporate purposes, including future public offerings, to raise additional capital or to facilitate acquisitions.

Our board of directors may generally issue shares of one or more series of preferred stock on terms calculated to discourage, delay or prevent a change of control of the Company or the removal of our management. Moreover, our authorized but unissued shares of preferred stock will be available for future issuances in one or more series without stockholder approval and could be utilized for a variety of corporate purposes, including future offerings to raise additional capital, to facilitate acquisitions and employee benefit plans.

One of the effects of the existence of authorized and unissued and unreserved common stock or preferred stock may be to enable our board of directors to issue shares to persons friendly to current management, which issuance could render more difficult or discourage an attempt to obtain control of the Company by means of a merger, tender offer, proxy contest or otherwise, and thereby protect the continuity of our management and possibly deprive our stockholders of opportunities to sell their shares of common stock at prices higher than prevailing market prices.

Classified Board of Directors

Our certificate of incorporation provides that our board of directors will be divided into three classes of directors, with each class to be as equal in number as possible, and with the directors serving staggered three-year terms. As a result, approximately one-third of our board of directors will be elected each year. The classification of directors will have the effect of making it more difficult for stockholders to change the composition of our board of directors. Our certificate of incorporation provides that, subject to any rights of holders of preferred stock to elect additional directors under specified circumstances, the total number of directors will be determined from time to time by the affirmative vote of a majority of the total number of directors then in office.

Delaware Law

We will be subject to the provisions of Section 203 of the DGCL regulating corporate takeovers. Section 203 of the DGCL provides that, subject to exceptions specified therein, an "interested stockholder" of a Delaware corporation shall not engage in any "business combination," including general mergers or consolidations or acquisitions of additional shares of the corporation, with the corporation for a three-year period following the time that such stockholder becomes an interested stockholder unless:

- prior to such time, the board of directors of the corporation approved either the business combination or the transaction that resulted in the stockholder becoming an interested stockholder;
- upon consummation of the transaction that resulted in the stockholder becoming an "interested stockholder," the interested stockholder owned at least 85% of the voting stock of the corporation outstanding at the time the transaction commenced (excluding specified shares); or
- at or subsequent to such time, the business combination is approved by the board of directors of the corporation and authorized at an annual or special meeting of stockholders, and not by written consent, by the affirmative vote of at least 66⅔% of the outstanding voting stock not owned by the interested stockholder.

Under Section 203 of the DGCL, the restrictions described above also do not apply to specified business combinations proposed by an interested stockholder following the announcement or notification of one of specified transactions involving the corporation and a person who had not been an interested stockholder during the previous three years or who became an interested stockholder with the approval of a majority of the corporation's directors, if such transaction is approved or not opposed by a majority of the directors who were directors prior to any person becoming an interested stockholder during the previous three years or were recommended for election or elected to succeed such directors by a majority of such directors.

Except as otherwise specified in Section 203 of the DGCL, an "interested stockholder" is defined to include:

- any person that is the owner of 15% or more of the outstanding voting stock of the corporation, or is an affiliate or associate of the corporation and was the owner of 15% or more of the outstanding voting stock of the corporation at any time within three years immediately prior to the date of determination; and
- the affiliates and associates of any such person.

Under some circumstances, Section 203 of the DGCL makes it more difficult for a person who is an interested stockholder to effect various business combinations with us for a three-year period following the time such stockholder became an interested stockholder.

A Delaware corporation may "opt out" of Section 203 of the DGCL with an express provision in its original certificate of incorporation or an express provision in its certificate of incorporation or bylaws resulting from amendments approved by the holders of at least a majority of the corporation's outstanding voting shares. We do not intend to "opt out" of the provisions of Section 203 of the DGCL. The statute could prohibit or delay mergers or other takeover or change in control attempts and, accordingly, may discourage attempts to acquire us.

Removal of Directors; Vacancies and Newly Created Directorships

Under the DGCL, unless otherwise provided in our certificate of incorporation, directors serving on a classified board may be removed by the stockholders only for cause. Our certificate of incorporation provides that directors may be removed only for cause and only by the affirmative vote of the holders of at least 60% in voting power of all the then-outstanding shares of our stock entitled to vote generally in the election of directors, voting together as a single class. In addition, our certificate of incorporation provides that, subject to the rights granted to the holders of one or more series of preferred stock then outstanding or the rights granted under our Stockholders' Agreement, any vacancies on our board of directors, and any newly created directorships, will be filled by a majority of the total number of directors then in office, even if less than a quorum, or by a sole remaining director, and not by the stockholders.

No Cumulative Voting

Under the DGCL, the right to vote cumulatively does not exist unless the certificate of incorporation specifically authorizes cumulative voting. Our certificate of incorporation does not authorize cumulative voting. Therefore, stockholders holding a majority in voting power of the shares of our stock entitled to vote generally in the election of directors will be able to elect all our directors, subject to certain nomination rights of BNAC under our Stockholders' Agreement. See "*Certain Relationships and Related Party Transactions — Stockholders' Agreement*."

Special Stockholder Meetings

Our certificate of incorporation provides that, subject to the rights of the holders of any series of preferred stock, special meetings of our stockholders may be called at any time only by or at the direction of our board of directors by the affirmative vote of a majority of the total number of directors then in office, the chairman of our board of directors or our Chief Executive Officer, and may not be called by any other person or persons. Our bylaws prohibit the conduct of any business at a special meeting other than as specified in the notice for such meeting. These provisions may have the effect of deterring, delaying or discouraging hostile takeovers, or changes in control or management of the Company.

Director Nominations and Stockholder Proposals

Our bylaws establish advance notice procedures with respect to stockholder proposals and the nomination of candidates for election as directors, other than nominations made by or at the direction of the board of directors or a committee of the board of directors. In order for any matter to be "properly brought" before a meeting, a stockholder will have to comply with advance notice requirements and provide us with certain information. Generally, to be timely, a stockholder's notice must be received at our principal executive offices not later than the close of business on the 90th day nor earlier than the close of business on the 120th day prior to the first anniversary date of the immediately preceding annual meeting of stockholders. Our bylaws also specify requirements as to the form and content of a stockholder's notice. Our bylaws allow the chairman of the meeting at a meeting of the stockholders to adopt rules and regulations for the conduct of meetings which may have the effect of precluding the conduct of certain business at a meeting if the rules and regulations are not followed. These provisions may also defer, delay or discourage a potential acquirer from conducting a solicitation of proxies to elect the acquirer's own slate of directors or otherwise attempting to influence or obtain control of the Company.

Stockholder Action by Written Consent

Under the DGCL, any action required to be taken at any annual or special meeting of the stockholders may be taken without a meeting, without prior notice and without a vote if a consent or consents in writing, setting forth the action so taken, is or are signed by the holders of outstanding stock having not less than the minimum number of votes that would be necessary to authorize or take such action at a meeting at which all shares of our stock entitled to vote thereon were present and voted, unless our certificate of incorporation provides otherwise. Our certificate of incorporation precludes stockholder action by written consent at any time when BNAC and its affiliates and subsidiaries (excluding the Company and its subsidiaries) own, in the aggregate, less than 35% in voting power of our stock entitled to vote generally in the election of directors.

Supermajority Provisions

Our governing documents provide that our board of directors is expressly authorized to make, repeal, alter, amend and rescind, in whole or in part, our bylaws by the affirmative vote of a majority of the total number of directors then in office, without the assent or vote of the stockholders in any matter not inconsistent with the laws of the State of Delaware or our certificate of incorporation. Any amendment, alteration, rescission or repeal of any provision of our bylaws, or the adoption of any provision inconsistent with our bylaws, by our stockholders requires the affirmative vote of the holders of at least 66⅔% in voting power of all the then-outstanding shares of our stock entitled to vote thereon, voting together as a single class, in addition to any vote of the holders of any class or series of our capital stock required by our governing documents or applicable law or securities exchange rule or regulation.

The DGCL provides generally that the affirmative vote of a majority of the outstanding shares entitled to vote thereon, voting together as a single class, is required to amend a corporation's certificate of incorporation, unless the certificate of incorporation requires a greater percentage.

Our certificate of incorporation provides that, in addition to any vote required by our governing documents or applicable law or securities exchange rule or regulation, the following provisions in our certificate of incorporation may be amended, altered, repealed or rescinded, in whole or in part, or any provision inconsistent therewith may be adopted, only by the affirmative vote of the holders of at least 66⅔% in voting power all the then-outstanding shares of our stock entitled to vote thereon, voting together as a single class (except that, in the case of any proposed amendment, alteration, repeal or rescission of, or the adoption of any provision inconsistent with, the following provisions, as to which the DGCL does not require the consent or vote of the stockholders or that is approved by at least 60% of our board of directors, then only the affirmative vote of the holders of a majority in voting power of all the then-outstanding shares of our stock entitled to vote thereon, voting together as a single class (in addition to any vote required by our governing documents or applicable law or securities exchange rule or regulation), will be required to amend, alter, repeal or rescind, or adopt any provision inconsistent with, the following provisions:

- the provisions requiring a 66⅔% supermajority vote for stockholders to amend our bylaws;

- the provisions providing for a classified board of directors (the election and term of our directors);
- the provisions regarding removal of directors;
- the provisions regarding filling vacancies on our board of directors and newly-created directorships;
- the provisions eliminating monetary damages for breaches of fiduciary duty by a director or officer;
- the provisions regarding indemnification and advancement of expenses to certain indemnitees in connection with certain proceedings;
- the provisions regarding stockholder action by written consent;
- the provisions regarding calling special meetings of stockholders;
- the provisions regarding competition and corporate opportunities; and
- the amendment provision requiring that the above provisions be amended with a majority vote or a 66⅔% supermajority vote, as applicable, of stockholders.

The combination of the classification of our board of directors, the lack of cumulative voting and the supermajority voting requirements in certain circumstances will make it more difficult for our existing stockholders to replace our board of directors as well as for another party to obtain control of us by replacing our board of directors. Because our board of directors has the power to retain and discharge our officers, these provisions could also make it more difficult for existing stockholders or another party to effect a change in management.

These provisions may have the effect of deterring hostile takeovers or delaying or preventing changes in control of us or our management, such as a merger, reorganization or tender offer. These provisions are intended to enhance the likelihood of continued stability in the composition of our board of directors and its policies and to discourage certain types of transactions that may involve an actual or threatened acquisition of the Company. These provisions are designed to reduce our vulnerability to an unsolicited acquisition proposal. The provisions are also intended to discourage certain tactics that may be used in proxy fights. However, such provisions could have the effect of discouraging others from making tender offers for our shares and, as a consequence, they also may inhibit fluctuations in the market price of our shares that could result from actual or rumored takeover attempts. Such provisions may also have the effect of preventing changes in management.

Dissenters' Rights of Appraisal and Payment

Under the DGCL, with certain exceptions, our stockholders will have appraisal rights in connection with a merger or consolidation of the Company. Pursuant to the DGCL, stockholders who properly request and perfect appraisal rights in connection with such merger or consolidation will have the right to receive payment of the fair value of their shares as determined by the Delaware Court of Chancery.

Stockholders' Derivative Actions

Under the DGCL, any of our stockholders may bring an action in our name to procure a judgment in our favor, also known as a derivative action, provided that the stockholder bringing the action is a holder of our shares at the time of the transaction to which the action relates or such stockholder's stock thereafter devolved by operation of law.

Choice of Forums

Our certificate of incorporation provides that unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware will, to the fullest extent permitted by law, be the sole and exclusive forum for any (i) derivative action or proceeding brought on behalf of the Company, (ii) action asserting a claim of breach of a fiduciary duty owed by any director, officer or employee of the Company to the Company or our stockholders, (iii) action asserting a claim against the Company or any director or officer of the Company arising pursuant to any provision of the DGCL or our governing documents, or (iv) action asserting a claim against the Company or any director, officer or employee of the Company, which claim is governed by the internal affairs doctrine. Notwithstanding the foregoing sentence, the federal district courts of the United States of America will be the exclusive forum for the resolution of any complaint asserting a cause of action arising under U.S. federal securities laws, including the Securities Act and the Exchange Act. Any person or entity purchasing or otherwise acquiring any interest in shares of capital stock of the Company will be deemed to have notice of and consented to the forum provisions in our certificate of incorporation. However, the enforceability of similar forum provisions in other companies' certificates of incorporation has been challenged in legal proceedings, and it is possible that a court could find these types of provisions to be unenforceable.

Corporate Opportunity

The DGCL permits corporations to adopt provisions renouncing any interest or expectancy of the corporation in, or in being offered an opportunity to participate in, specified business opportunities that are presented to the corporation or its officers, directors or stockholders. Our certificate of incorporation, to the fullest extent permitted by law, renounces any interest or expectancy that we have in, or right to be offered an opportunity to participate in, specified business opportunities that are from time to time presented to our officers, directors or stockholders or their respective affiliates, other than those officers, directors, stockholders or affiliates who are our or our subsidiaries' employees. Our certificate of incorporation provides that, to the fullest extent permitted by law, neither BNAC nor its affiliates or any director who is not employed by us (including any non-employee director who serves as one of our officers in both his or her director and officer capacities) or his or her affiliates will have any duty to refrain from (i) engaging in the same or similar business activities or lines of business in which we or our affiliates now engage or propose to engage or (ii) otherwise competing with us or our affiliates. In addition, to the fullest extent permitted by law, in the event that BNAC or its affiliates or any non-employee director acquires knowledge of a potential transaction or other business opportunity that may be a corporate opportunity for itself, himself or herself or its or his or her affiliates or for us or any of our affiliates, such person will have no duty to communicate or offer such transaction or business opportunity to us or any of our affiliates and they may take any such opportunity for themselves or offer it to another person or entity. Our certificate of incorporation does not renounce our interest in any corporate opportunity that is expressly offered to a non-employee director solely in his or her capacity as a director or officer of the Company. To the fullest extent permitted by law, a business opportunity will not be deemed to be a potential corporate opportunity for us if we would not be financially or legally able, or contractually permitted to undertake, the opportunity; the opportunity, from its nature, would not be in the line of our business; or the opportunity is one in which we would have no interest or reasonable expectancy.

In addition, in light of Mr. Kalnin's role on Banpu's Executive Committee, our Board has adopted a corporate opportunity policy that requires Mr. Kalnin to present applicable business opportunities of which he may become aware to our Company before such opportunities may be presented to Banpu or one of its affiliates. See "*Management — Conflicts of Interest*" for more information regarding our corporate opportunity policy.

Limitations of Liability and Indemnification

The DGCL authorizes corporations to limit or eliminate the personal liability of directors and certain officers to corporations and their stockholders for monetary damages for breaches of directors' or certain officers' fiduciary duties, subject to certain exceptions. Our certificate of incorporation includes a provision that eliminates the personal liability of our directors and officers for monetary damages to the Company or its stockholders for any breach of fiduciary duty as a director or an officer, to the fullest extent permitted by the DGCL. The effect of these provisions is to eliminate the rights of us and our stockholders, through stockholders' derivative suits on our behalf, to recover monetary damages from a director or an officer for breach of fiduciary duty as a director or an officer, including breaches resulting from grossly negligent behavior. However, exculpation does not apply to any breaches of the duty of loyalty, any acts or omissions not in good faith or that involve intentional misconduct or knowing violation of law, any authorization of dividends or stock redemptions or repurchases paid or made in violation of the DGCL, or for any transaction from which the director derived an improper personal benefit.

Our certificate of incorporation and our bylaws generally provide that we must defend, indemnify and advance expenses to our directors and officers to the fullest extent permitted by the DGCL. We also are expressly authorized to carry directors' and officers' liability insurance providing indemnification for our directors, officers and certain employees for some liabilities. We believe that these indemnification and advancement provisions and insurance are useful to attract and retain qualified directors and executive officers.

The limitation of liability, indemnification and advancement provisions in our certificate of incorporation and our bylaws may discourage stockholders from bringing a lawsuit against directors or officers for breach of their fiduciary duty. These provisions also may have the effect of reducing the likelihood of derivative litigation against directors and officers, even though such an action, if successful, might otherwise benefit us and our stockholders. In addition, your investment may be adversely affected to the extent we pay the costs of settlement and damage awards against directors and officers pursuant to these indemnification provisions.

There is currently no pending material litigation or proceeding involving any of our directors, officers or employees for which indemnification is sought.

Indemnification Agreements

We intend to enter into an indemnification agreement with each of our directors and officers as described in "*Certain Relationships and Related Party Transactions — Indemnification Agreements with our Directors and Officers*." Insofar as indemnification for liabilities arising under the Securities Act may be permitted to directors or officers, we have been informed that in the opinion of the SEC such indemnification is against public policy and is therefore unenforceable.

Registration Rights

Our Stockholders' Agreement will provide BNAC and its affiliates with the right, in certain circumstances, to require us to register their shares of our common stock constituting registrable securities under the Securities Act for sale into the public markets and with certain piggyback rights. Our Stockholders' Agreement will also provide that we will pay certain expenses of BNAC and its affiliates relating to such registrations and indemnify them against certain liabilities that may arise under the Securities Act. See "*Certain Relationships and Related Party Transactions — Registration Rights*" for a description of these registration rights.

Transfer Agent and Registrar

Upon completion of this offering, the transfer agent and registrar for our common stock will be Broadridge Corporate Issuer Solutions, Inc. The transfer agent and registrar's address is 51 Mercedes Way, Edgewood, New York 11717.

Listing

We have applied to list our common stock on the NYSE under the symbol "BKV."

SHARES ELIGIBLE FOR FUTURE SALE

Prior to this offering, there has been no public market for our common stock, and we cannot predict the effect, if any, that market sales of shares of our common stock or the availability of shares of our common stock for sale will have on the market price of our common stock prevailing from time to time. Future sales of our common stock in the public market, or the perception that those sales may occur, could adversely affect the prevailing market price of our common stock at such time, which could make it more difficult for you to sell your shares of common stock at a time and price that you consider appropriate, and could impair our ability to raise equity capital or use our common stock as consideration for acquisitions of other businesses, investments or other corporate purposes in the future.

Sale of Restricted Securities

Immediately upon completion of this offering, there will be outstanding shares of common stock (or if the underwriters exercise in full their option to purchase additional shares). Of these outstanding shares, shares of our common stock to be sold in this offering (or shares if the underwriters exercise in full their option to purchase additional shares) will be freely tradable without further restriction or registration under the Securities Act. This number does not reflect any shares of common stock that directors and executive officers may purchase through the reserved share program. Any shares purchased in this offering by our affiliates, as that term is defined in Rule 144 under the Securities Act, may be sold in the public market only if registered or if they qualify for an exemption from registration under Rule 144 or Rule 701 under the Securities Act, which rules are summarized below.

BNAC's shares of common stock will be deemed "restricted securities" as defined in Rule 144 under the Securities Act. These restricted securities may be sold in the public market only if they are registered or if they qualify for an exemption from registration under Rule 144 under the Securities Act. BNAC will agree to certain lock-up restrictions with the underwriters pursuant to which it will agree, subject to specific exceptions, not to sell any of our stock for 180 days following the date of this prospectus. See "— *Lock-Up Arrangements*" below and "*Underwriting*."

As a result of the lock-up agreements described below and the provisions of Rule 144 and Rule 701 under the Securities Act, the shares of our common stock (excluding the shares to be sold in this offering) that will be available for sale in the public market are as follows:

- no shares will be eligible for sale on the date of this prospectus or prior to 180 days after the date of this prospectus; and
- shares will be eligible for sale upon the expiration of the lock-up agreements beginning 180 days after the date of this prospectus and when permitted under Rule 144 or Rule 701.

Lock-Up Arrangements

In connection with the completion of this offering, (i) BNAC and all of our directors and executive officers will enter into lock-up agreements with the underwriters and (ii) each of the individuals who participate in the reserved share program will enter into lock-up agreements with an affiliate of Citigroup Global Markets Inc., a participating underwriter, pursuant to which they will agree not to offer, pledge, sell, contract to sell, sell any option or contract to purchase, purchase any option or contract to sell, grant any option, right or warrant to purchase, lend or otherwise transfer or dispose of, directly or indirectly, any shares of common stock or any securities convertible into or exercisable or exchangeable for shares of common stock for a period of at least 180 days following the date of this prospectus, subject to certain exceptions. As a result of these contractual restrictions, shares of our common stock and the other securities subject to lock-up agreements will not be eligible for sale until these agreements expire or the restrictions are waived by the underwriters or Merrill Lynch, as applicable. The representatives of the underwriters or Merrill Lynch, as applicable, may, in their discretion, release any of the securities subject to lock-up restrictions in whole or in part at any time. See "*Underwriting*."

Shares of our common stock which were issued in satisfaction of awards granted under the 2021 Plan are subject to resale restrictions. The holder may not, without the consent of the Company or the representatives of the underwriters (for 180 days from the date of the final prospectus), (1) sell, pledge, offer to sell, contract to sell, sell any option or contract to purchase, purchase any option or contract to sell, grant any option, right or warrant to purchase or otherwise transfer or dispose of, any shares of common stock or any securities convertible into or exercisable or exchangeable for common stock, or (2) enter into any swap or other arrangement that transfers to another, in whole or in part, any of the economic consequences of ownership of the common stock. See "*Executive Compensation — BKV Corporation 2021 Long Term Incentive Plan*."

Rule 144

In general, under Rule 144 as in effect on the date of this prospectus, once we have been subject to public company reporting requirements for at least 90 days, a person who has beneficially owned shares proposed to be sold for at least six months, including the holding period of any prior owner other than an affiliate of us, and who is not deemed to have been one of our affiliates for purposes of the Securities Act at any time during the 90 days preceding a sale, will be entitled to sell, upon expiration of the lock-up agreements described above, such shares without complying with the manner of sale, volume limitation or notice provisions of Rule 144, subject to compliance with the public information requirements of Rule 144. Such a non-affiliated person who has beneficially owned the shares proposed to be sold for at least one year, including the holding period of any prior owner other than an affiliate of us, will be entitled to sell these shares without limitation.

In general, under Rule 144, our affiliates or persons selling shares on behalf of our affiliates will be entitled to sell upon expiration of the 180-day lock-up period described above, within any three-month period, a number of shares that does not exceed the greater of:

- 1% of the number of shares of our common stock then outstanding, which will equal approximately shares immediately after this offering (or shares if the underwriters elect to exercise in full their option to purchase additional shares); or
- the average weekly trading volume of our common stock on the NYSE during the four calendar weeks before a notice of the sale is filed on Form 144 with respect to such sale.

Sales by our affiliates or persons selling shares on behalf of our affiliates under Rule 144 also are subject to manner of sale and notice provisions and to the availability of public information about us.

Rule 701

In general, under Rule 701 under the Securities Act, any of our employees, directors, officers, consultants or advisors who purchases shares from us in connection with a compensatory stock or option plan or other written agreement before the effective date of this offering is entitled to sell such shares 90 days after the effective date of this offering in reliance on Rule 144, without having to comply with the holding period requirement of Rule 144 and, in the case of non-affiliates, without having to comply with the public information, volume limitation or notice filing provisions of Rule 144. The SEC has indicated that Rule 701 will apply to typical stock options granted by an issuer before it becomes subject to the reporting requirements of the Exchange Act, along with the shares acquired upon exercise of such options, including exercises after the date of this prospectus.

Registration Statement on Form S-8

We intend to file with the SEC a registration statement on Form S-8 under the Securities Act promptly after the completion of this offering to register shares of our common stock subject to equity-based incentive awards which were granted under the 2021 Plan, and which are reserved for issuance under the 2022 Plan. See "*Executive Compensation — BKV Corporation 2021 Long Term Incentive Plan*" and "*Executive Compensation — BKV Corporation 2022 Equity and Incentive Compensation Plan*." The Form S-8 will also register shares of our common stock reserved for purchase under the ESPP. See "*Executive Compensation — BKV Corporation Employee Stock Purchase Plan*." The registration statement on Form S-8 is expected to become effective immediately upon filing, and shares of our common stock covered by the registration statement will then become eligible for sale in the public market, subject to the Rule 144 limitations applicable to affiliates and vesting restrictions. See "*Executive Compensation — BKV Corporation 2021 Long Term*

Incentive Plan," "*Executive Compensation — BKV Corporation 2022 Equity and Incentive Compensation Plan*" and "*Executive Compensation — BKV Corporation Employee Stock Purchase Plan*."

Registration Rights

Our Stockholders' Agreement will provide BNAC and its affiliates with the right, in certain circumstances, to require us to register their shares of our common stock constituting registrable securities under the Securities Act for sale into the public markets at any time following the date that is six months after the consummation of this offering. BNAC and its affiliates will also be entitled to certain piggyback rights with respect to future registrations or underwritten shelf takedowns, subject to certain limitations. "*Certain Relationships and Related Party Transactions — Registration Rights*" contains additional information regarding such rights.

CERTAIN ERISA CONSIDERATIONS

The following is a summary of certain considerations associated with the acquisition and holding of shares of our common stock by employee benefit plans that are subject to Title I of the Employee Retirement Income Security Act of 1974, as amended ("ERISA"), plans, individual retirement accounts and other arrangements that are subject to Section 4975 of the Code or employee benefit plans that are governmental plans (as defined in Section 3(32) of ERISA), certain church plans (as defined in Section 3(33) of ERISA), non-U.S. plans (as described in Section 4(b)(4) of ERISA) or other plans that are not subject to the foregoing but may be subject to provisions under any other federal, state, local, non-U.S. or other laws or regulations that are similar to such provisions of ERISA or the Code (collectively, "Similar Laws"), and entities whose underlying assets are considered to include "plan assets" of any such plan, account or arrangement (each, a "Plan").

This summary is based on the provisions of ERISA and the Code (and related regulations and administrative and judicial interpretations) as of the date of this registration statement. This summary does not purport to be complete, and no assurance can be given that future legislation, court decisions, regulations, rulings or pronouncements will not significantly modify the requirements summarized below. Any of these changes may be retroactive and may thereby apply to transactions entered into prior to the date of their enactment or release. This discussion is general in nature and is not intended to be all inclusive, nor should it be construed as investment or legal advice.

General Fiduciary Matters

ERISA and the Code impose certain duties on persons who are fiduciaries of a Plan subject to Title I of ERISA or Section 4975 of the Code (an "ERISA Plan") and prohibit certain transactions involving the assets of an ERISA Plan and its fiduciaries or other interested parties. Under ERISA and the Code, any person who exercises any discretionary authority or control over the administration of an ERISA Plan or the management or disposition of the assets of an ERISA Plan, or who renders investment advice for a fee or other compensation to an ERISA Plan, is generally considered to be a fiduciary of the ERISA Plan.

In considering an investment in shares of our common stock with a portion of the assets of any Plan, a fiduciary should consider the Plan's particular circumstances and all of the facts and circumstances of the investment and determine whether the acquisition and holding of shares of our common stock is in accordance with the documents and instruments governing the Plan and the applicable provisions of ERISA, the Code, or any Similar Law relating to the fiduciary's duties to the Plan, including, without limitation:

- whether the investment is prudent under Section 404(a)(1)(B) of ERISA and any other applicable Similar Laws;
- whether, in making the investment, the ERISA Plan will satisfy the diversification requirements of Section 404(a)(1)(C) of ERISA and any other applicable Similar Laws;
- whether the investment is permitted under the terms of the applicable documents governing the Plan;
- whether in the future there may be no market in which to sell or otherwise dispose of the shares of our common stock;
- whether the acquisition or holding of the shares of our common stock will constitute a "prohibited transaction" under Section 406 of ERISA or Section 4975 of the Code (see discussion under "— *Prohibited Transaction Issues*"); and
- whether the Plan will be considered to hold, as plan assets, (i) only shares of our common stock or (ii) an undivided interest in our underlying assets (see the discussion under "— *Plan Asset Issues*").

Prohibited Transaction Issues

Section 406 of ERISA and Section 4975 of the Code prohibit ERISA Plans from engaging in specified transactions involving plan assets with persons or entities who are "parties in interest," within the meaning of ERISA, or "disqualified persons," within the meaning of Section 4975 of the Code, unless an exemption is available. A party in interest or disqualified person who engages in a non-exempt prohibited transaction may be subject to excise taxes and other penalties and liabilities under ERISA and the Code. In addition, the fiduciary of the ERISA Plan that engages in such a non-exempt prohibited transaction may be subject to excise taxes, penalties and liabilities under ERISA and the Code. The acquisition and/or holding of shares of our common stock by an ERISA Plan with respect to which the issuer, the initial purchaser, or a guarantor is considered a party in interest or a disqualified person may constitute or result in a direct or indirect prohibited transaction under Section 406 of ERISA and/or Section 4975 of the Code, unless the investment is acquired and is held in accordance with an applicable statutory, class or individual prohibited transaction exemption.

Because of the foregoing, shares of our common stock should not be acquired or held by any person investing "plan assets" of any Plan, unless such acquisition and holding will not constitute a non-exempt prohibited transaction under ERISA and the Code or a similar violation of any applicable Similar Laws.

Plan Asset Issues

Additionally, a fiduciary of a Plan should consider whether the Plan will, by investing in us, be deemed to own an undivided interest in our assets, with the result that we would become a fiduciary of the Plan and our operations would be subject to the regulatory restrictions of ERISA, including its prohibited transaction rules, as well as the prohibited transaction rules of the Code and any other applicable Similar Laws.

The Department of Labor (the "DOL") regulations provide guidance with respect to whether the assets of an entity in which ERISA Plans acquire equity interests would be deemed "plan assets" under some circumstances. Under these regulations, an entity's assets generally would not be considered to be "plan assets" if, among other things:

(a) the equity interests acquired by ERISA Plans are "publicly offered securities" (as defined in the DOL regulations) — *i.e.*, the equity interests are part of a class of securities that is widely held by 100 or more investors independent of the issuer and each other, are freely transferable, and are either registered under certain provisions of the federal securities laws or sold to the ERISA Plan as part of a public offering under certain conditions;

(b) the entity is an "operating company" (as defined in the DOL regulations) — *i.e.*, it is primarily engaged in the production or sale of a product or service, other than the investment of capital, either directly or through a majority-owned subsidiary or subsidiaries; or

(c) there is no significant investment by "benefit plan investors" (as defined in the DOL regulations) — *i.e.*, immediately after the most recent acquisition by an ERISA Plan of any equity interest in the entity, less than 25% of the total value of each class of equity interest (disregarding certain interests held by persons (other than benefit plan investors) with discretionary authority or control over the assets of the entity or who provide investment advice for a fee (direct or indirect) with respect to such assets, and any affiliates thereof) is held by ERISA Plans, individual retirement accounts and certain other Plans (but not including governmental plans, foreign plans and certain church plans), and entities whose underlying assets are deemed to include plan assets by reason of a Plan's investment in the entity.

Due to the complexity of these rules and the excise taxes, penalties and liabilities that may be imposed upon persons involved in non-exempt prohibited transactions, it is particularly important that fiduciaries, or other persons considering acquiring and/or holding shares of our common stock on behalf of, or with the assets of, any Plan, consult with their counsel regarding the potential applicability of ERISA, Section 4975 of the Code and any Similar Laws to such investment and whether an exemption would be applicable to the acquisition and holding of shares of our common stock. Purchasers of shares of our common stock have the exclusive responsibility for ensuring that their acquisition and holding of shares of our common stock complies with the fiduciary responsibility rules of ERISA and does not violate the prohibited transaction rules of ERISA, the Code or applicable Similar Laws. The sale of shares of our common stock to a Plan is in no respect a representation by us or any of our affiliates or representatives that such an investment meets all relevant legal requirements with respect to investments by any such Plan or that such investment is appropriate for any such Plan.

MATERIAL U.S. FEDERAL INCOME TAX CONSEQUENCES TO NON-U.S. HOLDERS OF OUR COMMON STOCK

The following is a general discussion of material U.S. federal income tax consequences to non-U.S. holders (as defined herein) with respect to the ownership and disposition of our common stock. This discussion applies only to non-U.S. holders that acquire our common stock in this offering and hold such stock as a capital asset within the meaning of Section 1221 of the Code (generally, property held for investment purposes). This discussion is based on current provisions of the Code, U.S. Treasury regulations promulgated under the Code, and administrative rulings and court decisions in effect, all of which are subject to change at any time, possibly with retroactive effect. We have not sought and will not seek any rulings from the IRS regarding the matters discussed below.

For purposes of this discussion, the term “non-U.S. holder” means a beneficial owner of our common stock that is not, for U.S. federal income tax purposes, an entity or arrangement treated as a partnership or any of the following:

- a citizen or individual resident of the United States;
- a corporation, or other entity treated as a corporation for U.S. federal income tax purposes, created or organized in or under the laws of the United States, any state thereof or the District of Columbia;
- an estate the income of which is subject to U.S. federal income tax regardless of its source; or
- a trust (1) if a court within the United States is able to exercise primary supervision over the administration of the trust and one or more “United States persons” (as defined in Section 7701(a)(30) of the Code) has or have the authority to control all substantial decisions of the trust, or (2) that has a valid election in effect under applicable U.S. Treasury regulations to be treated as a “United States person.”

This discussion is for general information only and does not address all aspects of U.S. federal income taxation that may be important to a non-U.S. holder in light of that holder’s particular circumstances or that may be applicable to holders subject to special treatment under U.S. federal income tax law (including, for example, financial institutions, brokers or dealers in securities, traders in securities that elect mark-to-market treatment, insurance companies, controlled foreign corporations, passive investment companies, holders who acquire our common stock pursuant to the exercise of employee stock options or otherwise as compensation, entities or arrangements treated as partnerships for U.S. federal income tax purposes (and partners or beneficial owners therein), holders liable for the alternative minimum tax, certain former citizens or former long-term residents of the U.S., persons who hold or are deemed to hold our common stock as part of a hedge, straddle, constructive sale, conversion transaction or other risk-reduction transaction, persons required for U.S. federal income tax purposes to conform the timing of income accruals with respect to the common stock to their financial statements under Section 451 of the Code, tax-qualified retirement plans, tax-exempt organizations, and governmental organizations, and “qualified foreign pension funds” as defined in Section 897(l)(2) of the Code and entities all of the interests of which are held by qualified foreign pension funds). In addition, this discussion does not address U.S. federal tax laws other than those pertaining to the U.S. federal income tax, nor does it address any aspects of the Medicare contribution tax on net investment income, or U.S. state or local or non-U.S. taxes. This discussion also does not specifically address any tax treaties. Accordingly, prospective investors should consult their own tax advisors regarding the U.S. federal, state, local, and non-U.S. income and other tax considerations of acquiring, holding and disposing of shares of our common stock.

If a partnership (including an entity or arrangement treated as a partnership for U.S. federal income tax purposes) holds our common stock, the tax treatment of a partner in the partnership generally will depend upon the status of the partner, the activities of the partnership and certain determinations made at the partner level. Accordingly, we urge partners in partnerships (including entities or arrangements treated as partnerships for U.S. federal income tax purposes) considering the purchase of our common stock to consult their tax advisors regarding the U.S. federal income tax considerations of the ownership and disposition of our common stock by such partnership.

THIS SUMMARY IS FOR GENERAL INFORMATION ONLY. IT IS NOT TAX ADVICE. INVESTORS CONSIDERING THE PURCHASE OF OUR COMMON STOCK ARE URGED TO

CONSULT THEIR TAX ADVISORS REGARDING THE APPLICATION OF THE U.S. FEDERAL, STATE, LOCAL AND NON-U.S. INCOME AND OTHER TAX LAWS AND ANY APPLICABLE TAX TREATIES TO THEIR PARTICULAR SITUATIONS.

Distributions on Common Stock

We currently do not pay a fixed cash dividend to holders of our common stock, and our existing debt agreements place certain restrictions on our ability to pay cash dividends on our common stock. Our dividend policy is under consideration by our board of directors. Any future determination related to our dividend policy will be made at the sole discretion of our board of directors. See "*Dividend Policy*" for additional information.

In general, any distributions we make to a non-U.S. holder with respect to shares of our common stock that constitute dividends for U.S. federal income tax purposes will be subject to U.S. withholding tax at a rate of 30% (or such lower rate as may be specified by an applicable income tax treaty) of the gross amount distributed, unless the dividends are effectively connected with a trade or business carried on by the non-U.S. holder within the United States and, if required by an applicable income tax treaty, are attributable to a permanent establishment of the non-U.S. holder within the United States. A distribution will constitute a dividend for U.S. federal income tax purposes to the extent of our current or accumulated earnings and profits as determined for U.S. federal income tax purposes. Any distribution not constituting a dividend will be treated as first reducing the adjusted basis in the non-U.S. holder's shares of our common stock, but not below zero, and, to the extent it exceeds the adjusted basis in the non-U.S. holder's shares of our common stock, as capital gain and will be treated as described below under "— *Sale, Exchange or Other Taxable Disposition of Common Stock*." However, except to the extent that we elect (or the paying agent or other intermediary through which you hold your shares of common stock elects) to withhold with respect to the taxable portion of the distribution only, we (or the applicable paying agent or intermediary) must generally withhold on the entire distribution, in which case you generally would be entitled to a refund from the IRS by timely filing an appropriate claim for a refund, to the extent the withholding exceeds your tax liability with respect to the distribution.

A non-U.S. holder who wishes to claim the benefit of an applicable treaty rate on dividends will be required (a) to provide the applicable withholding agent with a properly executed IRS Form W-8BEN or W-8BEN-E (or other applicable form) certifying under penalties of perjury that such holder is not a U.S. person as defined under the Code and is eligible for treaty benefits or (b) if our common stock is held through certain foreign intermediaries, to satisfy the relevant certification requirements of applicable U.S. Treasury regulations. A non-U.S. holder that does not timely furnish the required documentation, but that is eligible for a lower rate of U.S. federal withholding tax pursuant to an income tax treaty, may obtain a refund or credit of any excess amounts withheld by filing an appropriate claim for a refund with the IRS. Non-U.S. holders are urged to consult their own tax advisors regarding their possible entitlement to benefits under an applicable income tax treaty.

Dividends effectively connected with a non-U.S. holder's conduct of a U.S. trade or business (and, if required by an applicable income tax treaty, attributable to such non-U.S. holder's U.S. permanent establishment) generally will not be subject to U.S. withholding tax if the non-U.S. holder complies with applicable certification requirements. More particularly, to claim this exemption from U.S. withholding tax, the non-U.S. holder must furnish to the applicable withholding agent a valid IRS Form W-8ECI, certifying that the dividends are effectively connected with the non-U.S. holder's conduct of a trade or business within the United States. Such effectively connected dividends, although not subject to withholding tax (provided the IRS Form W-8ECI certification requirements are satisfied), generally will be subject to U.S. federal income tax on a net income basis, at the regular graduated rates applicable to U.S. persons. A non-U.S. holder that is a corporation may be subject to an additional "branch profits tax" at a rate of 30% (or such lower rate as may be specified by an applicable income tax treaty) on its "effectively connected earnings and profits," subject to certain adjustments.

The foregoing is subject to the discussion below under "— *Information Reporting and Backup Withholding*" and "— *Foreign Account Tax Compliance Act*."

Sale, Exchange or Other Taxable Disposition of Common Stock

Subject to the discussion below under "— *Information Reporting and Backup Withholding*" and "— *Foreign Account Tax Compliance Act*," a non-U.S. holder will generally not be subject to U.S. federal income or withholding tax with respect to gain recognized on the sale, exchange or other taxable disposition of our common stock unless:

- the gain is effectively connected with a trade or business carried on by the non-U.S. holder within the United States and, if required by an applicable income tax treaty, is attributable to a U.S. permanent establishment of such non-U.S. holder,
- the non-U.S. holder is a nonresident alien individual and is present in the United States for 183 days or more in the taxable year of the sale, exchange or other taxable disposition and certain other conditions are satisfied, or
- we are or have been a "United States real property holding corporation" ("USRPHC") for U.S. federal income tax purposes at any time within the shorter of the five-year period ending on the date of the disposition of the common stock and the non-U.S. holder's holding period, and certain other conditions are satisfied.

Gain described in the first bullet point above (*i.e.*, gain that is effectively connected with the conduct of a trade or business in the United States) generally will be subject to U.S. federal income tax, net of certain deductions, at the regular graduated rates applicable to U.S. persons. If the non-U.S. holder is a foreign corporation, the branch profits tax at a rate of 30% (or such lower rate as may be specified by an applicable income tax treaty) also may apply to such effectively connected gain.

A non-U.S. holder described in the second bullet point above (*i.e.*, who is subject to U.S. federal income tax because the non-U.S. holder was present in the United States for 183 days or more during the taxable year of the sale, exchange or other taxable disposition of our common stock) will be subject to U.S. federal income tax at a rate of 30% (or such lower rate as may be specified under an applicable income tax treaty) on the gain derived from such sale, exchange or other taxable disposition, which may be offset by U.S. source capital losses, provided the non-U.S. holder has timely filed U.S. federal income tax returns with respect to such losses.

With respect to the third bullet point above, we are currently, and expect to continue to be for the foreseeable future, a USRPHC (and the remainder of this discussion assumes we are and will be a USRPHC). However, if our common stock is "regularly traded on an established securities market" (as defined by the U.S. Treasury regulations), a non-U.S. holder will be taxed on gain recognized on the disposition of our common stock as a result of our status as a USRPHC only if the non-U.S. holder actually or constructively holds or held more than 5% of our common stock at any time during the five-year period ending on the date of disposition or, if shorter, during the entire period the non-U.S. holder has held our common stock. If our common stock were not considered to be regularly traded on an established securities market, all non-U.S. holders would be subject to U.S. federal income tax on the sale, exchange or other taxable disposition of our common stock and a 15% withholding tax would apply to the gross proceeds from such sale, exchange or other taxable disposition of our common stock by a non-U.S. holder. Such withholding tax is not an additional tax but, rather, is credited against the actual U.S. federal income taxes owed by the non-U.S. holder (and such non-U.S. holder may obtain a refund of any amounts so withheld which exceed the non-U.S. holder's actual U.S. federal income tax liability, if any, provided that the non-U.S. holder makes the necessary filings with the IRS in a timely manner).

Information Reporting and Backup Withholding

We (or the applicable paying agent or intermediary) must report annually to the IRS and to each non-U.S. holder the amount of distributions paid to, and the tax withheld (if any) with respect to, each non-U.S. holder of our common stock. These reporting requirements apply regardless of whether withholding was reduced or eliminated by an applicable tax treaty. Copies of this information also may be made available under the provisions of a specific treaty or agreement with the tax authorities in the country in which the non-U.S. holder resides or is established.

U.S. backup withholding tax, at a rate that is currently 24%, is imposed on certain payments to persons that fail to furnish the information required under the U.S. information reporting rules. Dividends paid to a non-U.S. holder generally will be exempt from backup withholding if the non-U.S. holder provides a properly executed applicable IRS Form W-8, or otherwise establishes an exemption.

Under U.S. Treasury regulations, the payment of proceeds from the disposition of our common stock by a non-U.S. holder effected at a U.S. office of any broker (U.S. or non-U.S.), generally will be subject to information reporting and backup withholding, unless the beneficial owner certifies its status as a non-U.S. holder (generally by providing a properly executed applicable IRS Form W-8), or otherwise establishes an exemption. The payment of proceeds from the disposition of our common stock by a non-U.S. holder effected at a non-U.S. office of a broker that is neither a U.S. person nor a person having certain relationships with the United States generally will not be subject to backup withholding or information reporting. However, the payment of proceeds from a disposition of our common stock by a non-U.S. holder effected at a non-U.S. office of a broker that is a U.S. person or has certain relationships with the United States will generally be subject to information reporting, unless the beneficial owner certifies its status as a non-U.S. holder (generally by providing a properly executed applicable IRS Form W-8), or the broker has other documentary evidence in its files that the beneficial owner is a non-U.S. holder and certain other conditions are satisfied, or the beneficial owner otherwise establishes an exemption (and the broker has no knowledge or reason to know to the contrary). If the payment described in the preceding sentence is subject to information reporting, it will be subject to backup withholding if the broker has actual knowledge or reason to know that the payee is a U.S. person.

Backup withholding is not an additional tax but, rather, is credited against the actual U.S. federal income taxes owed by the non-U.S. holder. A non-U.S. holder may obtain a refund of any amounts withheld under the backup withholding rules which exceed the non-U.S. holder's actual U.S. federal income tax liability, if any, provided that the non-U.S. holder makes the necessary filings with the IRS in a timely manner.

Foreign Account Tax Compliance Act

Under Sections 1471 through 1474 of the Code and the U.S. Treasury regulations promulgated thereunder (collectively, "FATCA"), a U.S. federal withholding tax of 30% generally will be imposed on certain payments made to a "foreign financial institution" (as specifically defined under these rules) unless such institution enters into an agreement with the U.S. tax authorities to withhold on certain payments and to collect and provide to the U.S. tax authorities substantial information regarding U.S. account holders of such institution or meets other exceptions. Under FATCA and administrative guidance, a U.S. federal withholding tax of 30% generally also will be imposed on certain payments made to a "non-financial foreign entity" (as specifically defined under these rules) unless such entity provides the withholding agent with a certification identifying its direct and indirect U.S. owners or meets other exceptions. Foreign financial institutions located in jurisdictions that have an intergovernmental agreement with the U.S. governing these withholding and reporting requirements may be subject to different rules.

These withholding taxes would be imposed on dividends with respect to our common stock to foreign financial institutions or non-financial foreign entities (including in their capacity as agents or custodians for beneficial owners of our common stock) that fail to satisfy the above requirements. Prior to the issuance of proposed U.S. Treasury regulations, withholding taxes under FATCA also would have applied to gross proceeds from the disposition of our common stock. However, the proposed U.S. Treasury regulations provide that such gross proceeds are generally not subject to withholding taxes under FATCA. Taxpayers (including withholding agents) may currently rely on these proposed U.S. Treasury regulations until they are revoked or final U.S. Treasury regulations are issued.

Under certain circumstances, a non-U.S. holder might be eligible for refunds or credits of such taxes. Prospective non-U.S. holders should consult their tax advisors regarding the possible implications of FATCA on their investment in our common stock.

UNDERWRITING

Under the terms and subject to the conditions contained in an underwriting agreement dated as of the date of this prospectus (the “Underwriting Agreement”), we have agreed to sell to the underwriters named below, for whom Citigroup Global Markets Inc. and Barclays Capital Inc. are acting as representatives, the following respective numbers of shares of common stock:

Underwriter	Number of Shares
Citigroup Global Markets Inc.	
Barclays Capital Inc.	
Evercore Group L.L.C.	
Jefferies LLC	
Tudor, Pickering, Holt & Co. Securities, LLC	
Susquehanna Financial Group, LLLP	
Total	

The Underwriting Agreement provides that the underwriters are obligated to purchase all the shares of common stock in the offering if any are purchased, other than those shares covered by the option described below. The Underwriting Agreement also provides that if an underwriter defaults the purchase commitments of non-defaulting underwriters may be increased or the offering may be terminated.

We have agreed to indemnify the underwriters and certain of their controlling persons against certain liabilities, including liabilities under the Securities Act, and to contribute to payments that the underwriters may be required to make in respect of those liabilities.

We have granted to the underwriters a 30-day option to purchase on a pro rata basis up to additional shares at the initial public offering price less the underwriting discounts and commissions. The option may be exercised only to cover sales by the underwriters of a greater number of shares than the total number in the table above.

The underwriters propose to offer the shares of common stock initially at the public offering price on the cover page of this prospectus and to selling group members at that price less a selling concession of up to $ per share. After the initial public offering the underwriters may change the public offering price and concession.

The following table summarizes the underwriting discounts and commissions payable by us to the underwriters in connection with this offering, assuming both no exercise and full exercise of the underwriters' option to purchase additional shares.

	Per Share		Total	
	Without Option	With Option	Without Option	With Option
Underwriting discounts and commissions payable by us	$	$	$	$

The expenses of this offering that have been paid or are payable by us are estimated to be approximately $ million (excluding underwriting discounts and commissions). We have also agreed to reimburse the underwriters for certain of their expenses in an amount up to $.

We have agreed that, subject to certain exceptions, we will not offer, sell, contract to sell, pledge or otherwise dispose of, directly or indirectly, or file with the SEC a registration statement under the Securities Act relating to, any shares of our common stock or securities convertible into or exchangeable or exercisable for any shares of our common stock, or publicly disclose the intention to make any offer, sale, pledge, disposition or filing, without the prior written consent of the representatives for a period of 180 days after the date of this prospectus.

The representatives of the underwriters may, in their discretion, release the shares of our common stock or other securities subject to the lock-up agreements described above in whole or in part at any time.

Our officers and directors and certain of our stockholders have agreed that they will not offer, sell, contract to sell, pledge or otherwise dispose of, directly or indirectly, any shares of our common stock or securities convertible into or exchangeable or exercisable for any shares of our common stock, enter into a transaction that would have the same effect, or enter into any swap, hedge or other arrangement that transfers, in whole or in part, any of the economic consequences of ownership of our common stock, whether any of these transactions are to be settled by delivery of our common stock or other securities, in cash or otherwise, or publicly disclose the intention to make any such offer, sale, pledge or disposition, or to enter into any such transaction, swap, hedge or other arrangement, without, in each case, the prior written consent of the representatives for a period of 180 days after the date of this prospectus, subject to certain exceptions.

We have applied to list our common stock on the NYSE under the symbol "BKV."

In connection with the listing of the common stock on the NYSE, the underwriters will undertake to sell round lots of 100 shares or more to a minimum of 400 beneficial owners.

Prior to this offering, there has been no public market for our common stock. The initial public offering price was determined by negotiations among us and the representatives and will not necessarily reflect the market price of the common stock following this offering. The principal factors that were considered in determining the initial public offering price included:

- the information presented in this prospectus and otherwise available to the underwriters;
- the history of, and prospects for, the industry in which we will compete;
- the ability of our management;
- the prospects for our future earnings;
- the present state of our development, results of operations and our current financial condition;
- the general condition of the securities markets at the time of this offering; and
- the recent market prices of, and the demand for, publicly traded common stock of generally comparable companies.

We cannot assure you that the initial public offering price will correspond to the price at which the common stock will trade in the public market subsequent to this offering or that an active trading market for the common stock will develop and continue after this offering.

In connection with the offering the underwriters may engage in stabilizing transactions, short sales, syndicate covering transactions and penalty bids in accordance with Regulation M under the Exchange Act.

- Stabilizing transactions permit bids to purchase the underlying security so long as the stabilizing bids do not exceed a specified maximum.
- Short sales involve sales by the underwriters of shares in excess of the number of shares the underwriters are obligated to purchase, which creates a syndicate short position. The short position may be either a covered short position or a naked short position. In a covered short position, the short position is not greater than the number of shares for which the underwriters' option described above may be exercised. In a naked short position, the short position is greater than the number of shares for which the underwriters' option described above may be exercised.
- Syndicate covering transactions involve purchases of the common stock in the open market after the distribution has been completed in order to cover syndicate short positions. In determining the source of shares to close out the short position, the underwriters will consider, among other things, the price of shares available for purchase in the open market, as compared to the price at which they may purchase shares through their option. The underwriters may close out any covered short position by either exercising their option and/or purchasing shares in the open market. If the underwriters sell more shares than could be covered by their option, a naked short position, the position can only be closed out by buying shares in the open market. A naked short position is more likely to be created if the underwriters are concerned that there could be downward pressure on the price of the shares in the open market after pricing that could adversely affect investors who purchase in the offering.

- Penalty bids permit the representatives to reclaim a selling concession from a syndicate member when the common stock originally sold by the syndicate member is purchased in a stabilizing transaction or a syndicate covering transaction to cover syndicate short positions.

These stabilizing transactions, syndicate covering transactions and penalty bids may have the effect of raising or maintaining the market price of our common stock or preventing or retarding a decline in the market price of the common stock. As a result, the price of our common stock may be higher than the price that might otherwise exist in the open market. These transactions may be effected on the NYSE or otherwise and, if commenced, may be discontinued at any time.

The underwriters and certain of their affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, investment research, principal investment, hedging, financing and brokerage activities. The underwriters and certain of their affiliates have, from time to time, performed, and may in the future perform, various commercial and investment banking and financial advisory services for the issuer and its affiliates, for which they received, or may in the future receive, customary fees and expenses.

In the ordinary course of their various business activities, the underwriters and certain of their affiliates may make or hold a broad array of investments and actively trade debt and equity securities (or related derivative securities) and financial instruments (including bank loans) for their own account and for the accounts of their customers, and such investment and securities activities may involve securities and/or instruments of the issuer or its affiliates. If the underwriters or their affiliates have a lending relationship with us, certain of those underwriters or their affiliates may hedge their credit exposure to us consistent with their customary risk management policies. Typically, the underwriters and their affiliates would hedge such exposure by entering into transactions which consist of either the purchase of credit default swaps or the creation of short positions in our securities or the securities of our affiliates, including potentially the shares of common stock offered hereby. Any such credit default swaps or short positions could adversely affect future trading prices of the shares of common stock offered hereby. The underwriters and certain of their affiliates may also communicate independent investment recommendations, market color or trading ideas and/or publish or express independent research views in respect of such securities or instruments and may at any time hold, or recommend to clients that they acquire, long and/or short positions in such securities and instruments.

At our request, an affiliate of Citigroup Global Markets Inc., a participating underwriter, has reserved for sale, at the initial public offering price, up to 5% of the shares of common stock being offered by this prospectus for sale to some of our directors, executive officers, employees, business associates and related persons at the public offering price. If these persons purchase reserved shares, it will reduce the number of shares of common stock available for sale to the general public. Any reserved shares that are not so purchased will be offered by the underwriters to the general public on the same terms as the other shares offered by this prospectus. These persons must commit to purchase no later than the close of business on the day following the date of this prospectus. Any participants purchasing such reserved common stock will be prohibited from selling such stock for a period of 180 days after the date of this prospectus.

A prospectus in electronic format will be made available on the web sites maintained by one or more of the underwriters, or selling group members, if any, participating in this offering and one or more of the underwriters participating in this offering may distribute prospectuses electronically. The representatives may agree to allocate a number of shares to underwriters and selling group members for sale to their online brokerage account holders. Internet distributions will be allocated by the underwriters and selling group members that will make internet distributions on the same basis as other allocations.

Notice to Prospective Investors in Canada

The common stock may be sold only to purchasers purchasing, or deemed to be purchasing, as principal that are accredited investors, as defined in National Instrument 45-106 Prospectus Exemptions or subsection 73.3(1) of the Securities Act (Ontario), and are permitted clients, as defined in National Instrument 31-103 Registration Requirements, Exemptions and Ongoing Registrant Obligations. Any resale of the common stock must be made in accordance with an exemption from, or in a transaction not subject to, the prospectus requirements of applicable securities laws.

Securities legislation in certain provinces or territories of Canada may provide a purchaser with remedies for rescission or damages if this prospectus (including any amendment thereto) contains a misrepresentation, provided that the remedies for rescission or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province or territory. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province or territory for particulars of these rights or consult with a legal advisor.

Pursuant to section 3A.3 (or, in the case of securities issued or guaranteed by the government of a non-Canadian jurisdiction, section 3A.4) of National Instrument 33-105 Underwriting Conflicts, or NI 33-105, the underwriter is not required to comply with the disclosure requirements of NI 33-105 regarding underwriter conflicts of interest in connection with this offering.

Notice to Prospective Investors in the European Economic Area

In relation to each Member State of the European Economic Area (each an "EEA State"), no common stock has been offered or will be offered pursuant to the offering to the public in that EEA State prior to the publication of a prospectus in relation to the common stock which has been approved by the competent authority in that EEA State or, where appropriate, approved in another EEA State and notified to the competent authority in that EEA State, all in accordance with the EU Prospectus Regulation, except that it may make an offer to the public in that EEA State of any shares of common stock at any time under the following exemptions under the EU Prospectus Regulation:

- to any legal entity which is a qualified investor as defined under the EU Prospectus Regulation;
- to fewer than 150 natural or legal persons (other than qualified investors as defined under the EU Prospectus Regulation), subject to obtaining the prior consent of Citigroup Global Markets Inc. for any such offer; or
- in any other circumstances falling within Article 1(4) of the EU Prospectus Regulation,

provided that no such offer of the common stock shall require the Issuer or any underwriter to publish a prospectus pursuant to Article 3 of the EU Prospectus Regulation or supplement a prospectus pursuant to Article 23 of the EU Prospectus Regulation.

For the purposes of this provision, the expression an "offer to the public" in relation to the common stock in any EEA State means the communication in any form and by any means of sufficient information on the terms of the offer and any shares of common stock to be offered so as to enable an investor to decide to purchase or subscribe for any shares of common stock, and the expression "EU Prospectus Regulation" means Regulation (EU) 2017/1129.

Notice to Prospective Investors in the United Kingdom

In relation to the United Kingdom, no shares of common stock have been offered or will be offered pursuant to the offering to the public in the United Kingdom prior to the publication of a prospectus in relation to the common stock which has been approved by the Financial Conduct Authority in accordance with the transitional provision in Regulation 74 of the Prospectus (Amendment etc.) (EU Exit) Regulations 2019, except that it may make an offer to the public in the United Kingdom of any shares of common stock at any time under the following exemptions under the UK Prospectus Regulation:

- to any legal entity which is a qualified investor as defined under the UK Prospectus Regulation;
- to fewer than 150 natural or legal persons (other than qualified investors as defined under the UK Prospectus Regulation), subject to obtaining the prior consent of the representatives for any such offer; or
- in any other circumstances falling within Section 86 of the Financial Services and Markets Act 2000 (the "FSMA"),

provided that no such offer of the common stock shall require the Issuer or any underwriter to publish a prospectus pursuant to Section 85 of the FSMA or supplement a prospectus pursuant to Article 23 of the UK Prospectus Regulation.

In the United Kingdom, the offering is only addressed to, and is directed only at, “qualified investors” within the meaning of Article 2(e) of the UK Prospectus Regulation, who are also (i) persons having professional experience in matters relating to investments who fall within the definition of “investment professionals” in Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the “Order”); (ii) high net worth bodies corporate, unincorporated associations and partnerships and trustees of high value trusts as described in Article 49(2) of the Order; or (iii) persons to whom it may otherwise lawfully be communicated (all such persons being referred to as “relevant persons”). This document must not be acted on or relied on by persons who are not relevant persons. Any investment or investment activity to which this document relates is available only to relevant persons and will be engaged in only with relevant persons.

For the purposes of this provision, the expression an “offer to the public” in relation to the common stock in the United Kingdom means the communication in any form and by any means of sufficient information on the terms of the offering and any shares of common stock to be offered so as to enable an investor to decide to purchase or subscribe for any shares of common stock, and the expression “UK Prospectus Regulation” means the UK version of Regulation (EU) No 2017/1129 as amended by The Prospectus (Amendment etc.) (EU Exit) Regulations 2019, which is part of UK law by virtue of the European Union (Withdrawal) Act 2018.

Notice to Prospective Investors in the Dubai International Financial Centre

This prospectus relates to an Exempt Offer in accordance with the Offered Securities Rules of the Dubai Financial Services Authority (the “DFSA”). This prospectus is intended for distribution only to persons of a type specified in the Offered Securities Rules of the DFSA. It must not be delivered to, or relied on by, any other person. The DFSA has no responsibility for reviewing or verifying any documents in connection with Exempt Offers. The DFSA has not approved this prospectus nor taken steps to verify the information set forth herein and has no responsibility for the prospectus. The securities to which this prospectus relates may be illiquid and/or subject to restrictions on their resale. Prospective purchasers of the securities offered should conduct their own due diligence on the securities. If you do not understand the contents of this prospectus you should consult an authorized financial advisor.

Notice to Prospective Investors in Australia

No placement document, prospectus, product disclosure statement or other disclosure document has been lodged with the Australian Securities and Investments Commission, in relation to the offering. This prospectus does not constitute a prospectus, product disclosure statement or other disclosure document under the Corporations Act 2001 (the “Corporations Act”), and does not purport to include the information required for a prospectus, product disclosure statement or other disclosure document under the Corporations Act.

Any offer in Australia of the securities may only be made to persons (the “Exempt Investors”) who are “sophisticated investors” (within the meaning of section 708(8) of the Corporations Act), “professional investors” (within the meaning of section 708(11) of the Corporations Act) or otherwise pursuant to one or more exemptions contained in section 708 of the Corporations Act so that it is lawful to offer the securities without disclosure to investors under Chapter 6D of the Corporations Act.

The securities applied for by Exempt Investors in Australia must not be offered for sale in Australia in the period of 12 months after the date of allotment under the offering, except in circumstances where disclosure to investors under Chapter 6D of the Corporations Act would not be required pursuant to an exemption under section 708 of the Corporations Act or otherwise or where the offer is pursuant to a disclosure document which complies with Chapter 6D of the Corporations Act. Any person acquiring securities must observe such Australian on-sale restrictions. This prospectus contains general information only and does not take account of the investment objectives, financial situation or particular needs of any particular person. It does not contain any securities recommendations or financial product advice. Before making an investment decision, investors need to consider whether the information in this prospectus is appropriate to their needs, objectives and circumstances, and, if necessary, seek expert advice on those matters.

Notice to Prospective Investors in Switzerland

The common stock may not be publicly offered, directly or indirectly, in Switzerland within the meaning of the Swiss Financial Services Act (the “FinSA”) and no application has or will be made to admit the common stock to trading on any trading venue (exchange or multilateral trading facility) in Switzerland. Neither this prospectus nor any other offering or marketing material relating to the common stock constitutes a prospectus pursuant to the FinSA, and neither this prospectus nor any other offering or marketing material relating to the common stock may be publicly distributed or otherwise made publicly available in Switzerland.

Notice to Prospective Investors in Hong Kong

The common stock may not be offered or sold in Hong Kong by means of any document other than (i) in circumstances which do not constitute an offer to the public within the meaning of the Companies Ordinance (Cap. 32, Laws of Hong Kong), or (ii) to “professional investors” within the meaning of the Securities and Futures Ordinance (Cap. 571, Laws of Hong Kong) and any rules made thereunder, or (iii) in other circumstances which do not result in the document being a “prospectus” within the meaning of the Companies Ordinance (Cap. 32, Laws of Hong Kong) and no advertisement, invitation or document relating to the common stock may be issued or may be in the possession of any person for the purpose of issue (in each case whether in Hong Kong or elsewhere), which is directed at, or the contents of which are likely to be accessed or read by, the public in Hong Kong (except if permitted to do so under the laws of Hong Kong) other than with respect to common stock which are or are intended to be disposed of only to persons outside Hong Kong or only to “professional investors” within the meaning of the Securities and Futures Ordinance (Cap. 571, Laws of Hong Kong) and any rules made thereunder.

Notice to Prospective Investors in Singapore

This prospectus has not been registered as a prospectus with the Monetary Authority of Singapore. Accordingly, this prospectus and any other document or material in connection with the offer or sale, or invitation for subscription or purchase, of the common stock may not be circulated or distributed, nor may the common stock be offered or sold, or be made the subject of an invitation for subscription or purchase, whether directly or indirectly, to persons in Singapore other than (i) to an institutional investor under Section 274 of the Securities and Futures Act, Chapter 289 of Singapore (the “SFA”), (ii) to a relevant person pursuant to Section 275(1), or any person pursuant to Section 275(1A), and in accordance with the conditions specified in Section 275 of the SFA or (iii) otherwise pursuant to, and in accordance with the conditions of, any other applicable provision of the SFA, in each case subject to compliance with conditions set forth in the SFA.

Solely for the purposes of its obligations pursuant to sections 309B(1)(a) and 309B(1)(c) of the SFA and the Securities and Futures (Capital Markets Products) Regulations 2018 of Singapore (the “CMP Regulations 2018”), the Issuer has determined, and hereby notifies all relevant persons (as defined in Section 309A of the SFA) that the shares of common stock are (A) prescribed capital markets products (as defined in the CMP Regulations 2018) and (B) Excluded Investment Products (as defined in MAS Notice SFA 04-N12: Notice on the Sale of Investment Products and MAS Notice FAA-N16: Notice on Recommendations on Investment Products).

Notice to Prospective Investors in Thailand

This prospectus does not, and is not intended to, constitute a public offering in Thailand. The common stock may not be offered or sold to persons in Thailand, unless such offering is made under the exemptions from approval and filing requirements under applicable laws, or under circumstances which do not constitute an offer for sale of the common stock to the public for the purposes of the Securities and Exchange Act of 1992 of Thailand, nor require approval from the Office of the Securities and Exchange Commission of Thailand.

Where the shares of common stock are subscribed or purchased under Section 275 of the SFA by a relevant person which is:

- a corporation (which is not an accredited investor (as defined in Section 4A of the SFA)) the sole business of which is to hold investments and the entire share capital of which is owned by one or more individuals, each of whom is an accredited investor; or
- a trust (where the trustee is not an accredited investor) whose sole purpose is to hold investments and each beneficiary is an accredited investor,

shares, debentures and units of shares and debentures of that corporation or the beneficiaries' rights and interest (howsoever described) in that trust will not be transferred within six months after that corporation or that trust has acquired the shares pursuant to an offer made under Section 275 of the SFA except:

- to an institutional investor (for corporations, under Section 274 of the SFA) or to a relevant person defined in Section 275(2) of the SFA, or to any person pursuant to an offer that is made on terms that such shares, debentures and units of shares and debentures of that corporation or such rights and interest in that trust are acquired at a consideration of not less than S$200,000 (or its equivalent in a foreign currency) for each transaction, whether such amount is to be paid for in cash or by exchange of securities or other assets, and further for corporations, in accordance with the conditions specified in Section 275 of the SFA;
- where no consideration is or will be given for the transfer; or
- where the transfer is by operation of law.

Notice to Prospective Investors in Japan

Shares of our common stock have not been and will not be registered under the Financial Instruments and Exchange Law of Japan (Law No. 25 of 1948, as amended) and, accordingly, will not be offered or sold, directly or indirectly, in Japan, or for the benefit of any Japanese Person or to others for re-offering or resale, directly or indirectly, in Japan or to any Japanese Person, except in compliance with all applicable laws, regulations and ministerial guidelines promulgated by relevant Japanese governmental or regulatory authorities in effect at the relevant time. For the purposes of this paragraph, "Japanese Person" shall mean any person resident in Japan, including any corporation or other entity organized under the laws of Japan.

LEGAL MATTERS

The validity of the common stock offered hereby and certain other legal matters in connection with this offering will be passed upon for us by Baker Botts L.L.P., Dallas, Texas. Certain legal matters in connection with this offering will be passed upon for the underwriters by Latham & Watkins LLP, Houston, Texas. Baker Botts L.L.P. has from time to time represented and may continue to represent BKV and some of its affiliates in connection with various legal matters.

EXPERTS

The consolidated financial statements as of December 31, 2023 and 2022 and for each of the three years in the period ended December 31, 2023 included in this Prospectus have been so included in reliance on the report of PricewaterhouseCoopers LLP (“PwC”), an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

In connection with this registration statement, PwC completed an independence assessment to evaluate the services and relationships with the Company and its affiliates that may bear on PwC’s independence under the SEC and the PCAOB independence rules for an audit period commencing January 1, 2020. PwC informed the Company’s Audit & Risks Committee that one of its member firms within PricewaterhouseCoopers International Limited, each member firm of which is a separate legal entity (a “PwC member firm”), provided non-audit services during the audit period to two sister entities under common control with BKV Corporation. The services that occurred from January 2020 to June 2021, which are inconsistent with the SEC and PCAOB independence rules, involved the provision of corporate secretarial services and the disbursement of incidental payments on behalf of client management. The fees for these services totaled approximately $8,500 and $10,000, respectively, for the years ended December 31, 2021 and 2020. The provision of corporate secretarial services and the incidental payments made on behalf of client management are in contravention of SEC Rule 2-01(c)(4)(vi) of Regulation S-X.

PwC informed the Company’s Audit & Risks Committee of the facts and circumstances surrounding the impermissible services, noting that (i) the PwC member firm did not make any decisions or judgments on management’s behalf, and management reviewed and approved all documentation prepared by the PwC member firm, (ii) no aspect of the financial results of the sister entities or the provision of the services is included in (or has any impact on) the financial results of the Company, (iii) the services were performed by persons who were not part of the PwC audit engagement team, and (iv) the fees for the services were not material to the Company, the sister entities, the PwC member firm, or PwC. Additionally, the services do not create a mutual or conflicting interest between PwC and the Company, do not place PwC in a position of auditing its own work, and do not place PwC in a position of being an advocate for the Company.

After considering the facts and circumstances, the Company’s Audit & Risks Committee concurred with PwC’s conclusion that, for the reasons described above, the impermissible services did not impair PwC’s objectivity and impartiality with respect to the planning and execution of the audits of the Company’s consolidated financial statements as of December 31, 2023 and 2022 and for each of the three years in the period ended December 31, 2023, and that no reasonable investor would conclude otherwise.

Estimates of our natural gas reserves, related future net cash flows and the present values thereof related to our properties as of December 31, 2023, 2022 and 2021 included elsewhere in this prospectus were based upon reserves reports prepared by independent petroleum engineers Ryder Scott Company, L.P. We have included these estimates in reliance on the authority of such firms as experts in such matters.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC a registration statement on Form S-1 under the Securities Act with respect to the shares of common stock offered by this prospectus. This prospectus, which constitutes a part of the registration statement, does not contain all of the information set forth in the registration statement, some of which is contained in exhibits to the registration statement as permitted by the rules and regulations of the SEC. For further information with respect to us and our common stock, we refer you to the registration statement, including the exhibits filed as part of the registration statement. Statements contained in this prospectus concerning the contents of any contract or any other document are not necessarily complete, and each such statement is qualified in all respects by reference to the full text of such contract or other document filed as an exhibit to the registration statement.

The SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at *www.sec.gov*. Our filings with the SEC, including the registration statement, are available to you for free on the SEC's internet website.

Upon completion of this offering, we will become subject to the informational and reporting requirements of the Exchange Act and, in accordance with those requirements, will file reports and proxy and information statements with the SEC. We intend to furnish to our stockholders our annual reports containing audited consolidated financial statements and the notes thereto certified by an independent public accounting firm.

We also maintain an internet website at*www.bkvcorp.com*. Information on or accessible through our website is not part of this prospectus.

INDEX TO FINANCIAL STATEMENTS

BKV CORPORATION

Audited Consolidated Financial Statements

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of BKV Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of BKV Corporation and its subsidiaries (the "Company") as of December 31, 2023 and 2022, and the related consolidated statements of operations, of stockholders' equity, partners' capital and mezzanine equity and of cash flows for each of the three years in the period ended December 31, 2023, including 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 as of December 31, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (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 of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated 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 consolidated 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 consolidated 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 consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Dallas, Texas
April 29, 2024

We have served as the Company's auditor since 2020.

BKV CORPORATION

CONSOLIDATED BALANCE SHEETS
(in thousands, except per share amounts)

	December 31, 2023	December 31, 2022
Assets		
Current assets		
Cash and cash equivalents	$ 25,407	$ 153,128
Restricted cash	139,662	—
Accounts receivable, net	48,500	143,537
Accounts receivable, related parties	559	416
Commodity derivative assets, current	84,039	2,651
Other current assets	13,990	20,408
Total current assets	312,157	320,140
Natural gas properties and equipment		
Developed properties	2,370,156	2,252,681
Undeveloped properties	15,846	15,511
Midstream assets	318,855	317,109
Accumulated depreciation, depletion, and amortization	(579,415)	(375,783)
Total natural gas properties, net	2,125,442	2,209,518
Other property and equipment, net	83,935	39,865
Goodwill	18,417	18,417
Investment in joint venture	104,750	97,885
Commodity derivative assets	18,508	816
Other noncurrent assets	19,937	15,932
Total assets	$2,683,146	$2,702,573
Liabilities, mezzanine equity, and stockholders' equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 149,173	$ 272,475
Contingent consideration payable	20,000	65,000
Commodity derivative liabilities, current	—	49,484
Income taxes payable to related party	864	5,227
Credit facilities	127,000	90,000
Current portion of long-term debt, net	112,373	112,001
Other current liabilities	2,849	2,446
Total current liabilities	412,259	596,633
Asset retirement obligations	193,205	181,135
Contingent consideration	29,676	88,051
Note payable to related party	75,000	75,000
Deferred tax liability, net	136,524	104,130
Long-term debt, net	339,663	452,036
Other noncurrent liabilities	11,652	9,664
Total liabilities	1,197,979	1,506,649

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

BKV CORPORATION

CONSOLIDATED BALANCE SHEETS
(in thousands, except per share amounts)

	December 31, 2023	December 31, 2022
Commitments and contingencies (*Note 16*)		
Mezzanine equity		
Common stock – Minority ownership puttable shares; 2,403 authorized shares; 2,403 and 2,290 shares issued and outstanding as of December 31, 2023 and 2022, respectively	59,988	62,712
Equity-based compensation	126,966	89,171
Total mezzanine equity	186,954	151,883
Stockholders' equity		
Common stock, $0.01 par value; 300,000 authorized shares; 63,873 and 56,373 shares issued and outstanding as of December 31, 2023 and 2022, respectively	1,283	1,132
Treasury stock, shares at cost; 213 shares and 193 shares as of December 31, 2023 and 2022, respectively	(4,582)	(3,974)
Additional paid-in capital	1,034,144	896,433
Retained earnings	267,368	150,450
Total stockholders' equity	1,298,213	1,044,041
Total liabilities, mezzanine equity, and stockholders' equity	$2,683,146	$2,702,573

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

BKV CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share amounts)

	Year Ended December 31,		
	2023	**2022**	**2021**
Revenues and other operating income			
Natural gas, NGL, and oil sales	$706,151	$1,633,747	$ 829,745
Midstream revenues	16,168	12,676	6,917
Derivative gains (losses), net	238,743	(629,701)	(383,847)
Marketing revenues	8,710	11,001	52,616
Related party and other	8,251	2,799	251
Total revenues and other operating income	978,023	1,030,522	505,682
Operating expenses			
Lease operating and workover	150,647	131,497	86,831
Taxes other than income	72,290	114,668	45,650
Gathering and transportation	248,990	208,758	173,587
Depreciation, depletion, amortization, and accretion	223,370	118,909	92,277
General and administrative	114,688	148,559	85,740
Other	12,625	3,567	1,274
Total operating expenses	822,610	725,958	485,359
Income from operations	155,413	304,564	20,323
Other income (expense)			
Bargain purchase gain	—	170,853	—
Gain on settlement of litigation	—	16,866	—
Gains (losses) on contingent consideration liabilities	38,375	6,632	(194,968)
Earnings from equity affiliate	16,865	8,493	910
Interest income	3,138	1,143	8
Interest expense	(69,942)	(26,322)	—
Interest expense, related party	(7,078)	(10,846)	(2,134)
Other income	8,372	1,411	872
Income (loss) before income taxes	145,143	472,794	(174,989)
Income tax benefit (expense)	(28,225)	(62,652)	40,526
Net income (loss) attributable to BKV Corporation	116,918	410,142	(134,463)
Less accretion of preferred stock to redemption value	—	—	(3,745)
Less preferred stock dividends	—	—	(9,900)
Less deemed dividend on redemption of preferred stock	—	—	(22,606)
Net income (loss) attributable to common stockholders	$116,918	$ 410,142	$(170,714)
Net income (loss) per common share:			
Basic	$ 1.93	$ 6.99	$ (2.92)
Diluted	$ 1.82	$ 6.62	$ (2.92)
Weighted average number of common shares outstanding:			
Basic	60,730	58,659	58,496
Diluted	64,380	61,990	58,496

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

BKV CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2023	2022	2021
Cash flows from operating activities:			
Net income (loss)	$ 116,918	$ 410,142	$(134,463)
Adjustments to reconcile to net cash provided by operating activities:			
Depreciation, depletion, amortization, and accretion	224,427	130,038	98,833
Equity-based compensation expense	25,756	31,947	30,387
Deferred income tax (benefit) expense	32,394	89,065	(72,753)
Unrealized (gains) losses on derivatives, net	(148,564)	(58,815)	115,161
(Gains) losses on contingent consideration liabilities	(38,375)	(6,632)	194,968
Settlement of contingent consideration	(65,000)	(45,300)	—
Gain on bargain purchase	—	(170,853)	—
Earnings from equity affiliate	(16,865	(8,493	(910
Distribution from equity affiliate	10,000)	—)	—)
Other, net	822	911	48
Changes in operating assets and liabilities:			
Accounts receivable, net	86,477	(39,394)	(24,689)
Accounts receivable, related parties	(143)	3,082	(3,498)
Accounts payable and accrued liabilities	(98,238)	62,539	137,550
Other changes in operating assets and liabilities	(6,533)	(49,043)	17,499
Net cash provided by operating activities	123,076	349,194	358,133
Cash flows from investing activities:			
Business combination	—	(619,437)	—
Investment in joint venture	—	(72)	(88,410)
Acquisition of natural gas properties	(4,889)	—	(2,528)
Investment in other property and equipment	(52,066)	(11,787)	(2,249)
Development of natural gas properties	(134,428)	(235,406)	(63,932)
Loan advanced to equity affiliate	(8,000)	—	—
Loan repayment from equity affiliate	8,000	—	—
Other investing activities	13,535	1,136	(4,739)
Net cash used in investing activities	(177,848)	(865,566)	(161,858)
Cash flows from financing activities:			
Proceeds from notes payable from related party	17,000	75,000	166,000
Payments on notes payable to related party	(17,000)	(166,000)	(24,000)
Proceeds under term loan agreement	—	570,000	—
Payment on term loan agreement	(114,000)	—	—
Payment of debt issuance costs	—	(7,738)	—
Proceeds from draws on credit facilities	375,500	190,000	—
Payments on credit facilities	(338,500)	(100,000)	—
Settlement of contingent consideration	—	(19,700)	—
Payments of deferred offering costs	(2,901)	(5,625)	—
Redemption of minority ownership puttable shares	—	—	(2,754)
Issuance of minority ownership puttable shares	—	78	3,177
Dividends paid to preferred stock shareholders	—	—	(10,330)
Proceeds from the issuance of common stock	150,005	—	(121,275)
Dividends paid to common stock shareholders	—	—	(88,126)
Redemption of common stock	—	—	(1,106)
Redemption of common stock issued upon vesting of equity-based compensation and other	(426)	(4)	(110)
Shares repurchased in conjunction with reverse stock split	(4)	—	—
Net share settlements, equity-based compensation	(2,961)	(1,178)	(529)
Net cash provided by (used in) financing activities	66,713	534,833	(79,053)
Net increase in cash, cash equivalents, and restricted cash	11,941	18,461	117,222
Cash, cash equivalents, and restricted cash, beginning of period	153,128	134,667	17,445
Cash, cash equivalents, and restricted cash, end of period	$ 165,069	$ 153,128	$ 134,667

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

BKV CORPORATION

SUPPLEMENTAL CASH FLOW INFORMATION
(in thousands)

	Year Ended December 31,		
	2023	2022	2021
Supplemental cash flow information:			
Cash payments for:			
Interest	$ 68,480	$ 32,086	$ 393
Income tax	$ 1,545	$ 400	$ —
Non-cash investing and financing activities:			
Increase (decrease) in accrued capital expenditures	$ (23,863)	$ 19,247	$ 12,297
Additions to asset retirement obligations	$ 89	$ 302	$ 923
Revisions to asset retirement obligation estimates	$ —	$ 36,516	$ —
Lease liabilities arising from obtaining right-of-use assets	$ 3,061	$ 1,218	$ 11,249
Increase (decrease) in accrued offering costs	$ (604)	$ 945	$ —
Fair value of contingent consideration from acquisitions	$ —	$ 17,150	$ —
Adjustment of minority ownership puttable shares to redemption value	$ 2,722	$ 12,793	$ 7,042
Adjustment of equity-based compensation to redemption value	$ 15,602	$ 24,400	$ 4,236
Impact of redemption of minority interest puttable shares on additional paid-in capital, common stock, and treasury stock	$ 781	$ 4	$ 2,754
Accretion of preferred stock to redemption value	$ —	$ —	$ 3,745

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

BKV CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY, PARTNERS' CAPITAL, AND MEZZANINE EQUITY

(in thousands, except per share amounts)

	Stockholders' Equity						Mezzanine Equity				
	Common Stock							Common Stock			
	Shares	Amount	Treasury	Additional Paid-in Capital	Retained Earnings (Deficit)	Total Stockholders' Equity	Preferred Stock	Shares	Amount	Equity-based Compensation	Total Mezzanine Equity
Balances, December 31, 2020	56,428	$1,129	$ —	$968,500	$ (26,773)	$ 942,856	$ 94,924	2,114	$42,288	$ —	$137,212
Net loss	—	—	—	—	(134,463)	(134,463)	—	—	—	—	—
Dividend declared, preferred stock shareholders ($0.50 per share)	—	—	—	—	(10,330)	(10,330)	—	—	—	—	—
Accretion of preferred stock to redemption value	—	—	—	(3,745)	—	(3,745)	3,745	—	—	—	3,745
Deemed dividend, preferred stock shareholders	—	—	—	(22,606)	—	(22,606)	—	—	—	—	—
Redemption of preferred stock	—	—	—	—	—	—	(98,669)	—	—	—	(98,669)
Redemption of common stock	(50)	—	(1,106)	—	—	(1,106)	—	—	—	—	—
Purchase of vested equity-based compensation award shares of common stock	(5)	—	(110)	—	—	(110)	—	—	—	—	—
Redemption of minority ownership puttable common stock shares	—	3	(2,754)	2,751	—	—	—	(138)	(2,754)	—	(2,754)
Dividend declared ($1.50 per share)	—	—	—	—	(88,126)	(88,126)	—	—	—	—	—
Issuance of common stock from employee stock purchase plan	—	—	—	—	—	—	—	144	3,265	—	3,265
Adjustment of minority ownership puttable shares to redemption value	—	—	—	(7,042)	—	(7,042)	—	—	7,042	—	7,042
Issuance of common stock upon vesting of equity-based compensation awards	—	—	—	—	—	—	—	58	—	—	—
Impact of modification of equity-based compensation plan	—	—	—	—	—	—	—	—	—	25,342	25,342
Capital contribution from modification of equity-based compensation plan	—	—	—	780	—	780	—	—	—	—	—
Equity-based compensation	—	—	—	—	—	—	—	—	—	3,648	3,648
Adjustment of equity-based compensation to redemption value	—	—	—	(5,016)	—	(5,016)	—	—	—	5,016	5,016
Balances, December 31, 2021	56,373	$1,132	$(3,970)	$933,622	$(259,692)	$ 671,092	$ —	2,178	$49,841	$ 34,006	$ 83,847
Net income	—	—	—	—	410,142	410,142	—	—	—	—	—
Redemption of common stock issued upon vesting of equity-based compensation	—	—	(4)	4	—	—	—	—	—	(4)	(4)
Issuance of common stock from employee stock purchase plan	—	—	—	—	—	—	—	2	78	—	78
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income taxes	—	—	—	—	—	—	—	110	—	(1,178)	(1,178)
Adjustment of minority ownership puttable shares to redemption value	—	—	—	(12,793)	—	(12,793)	—	—	12,793	—	12,793
Adjustment of equity-based compensation to redemption value	—	—	—	(24,400)	—	(24,400)	—	—	—	24,400	24,400
Equity-based compensation	—	—	—	—	—	—	—	—	—	31,947	31,947
Balances, December 31, 2022	56,373	$1,132	$(3,974)	$896,433	$ 150,450	$1,044,041	$ —	2,290	$62,712	$ 89,171	$151,883
Net income	—	—	—	—	116,918	116,918	—	—	—	—	—
Redemption of common stock issued upon vesting of equity-based compensation	—	1	(604)	736	—	133	—	(21)	(2)	(602)	(604)

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

BKV CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY, PARTNERS' CAPITAL, AND MEZZANINE EQUITY
(in thousands, except per share amounts)

	Stockholders' Equity						Mezzanine Equity				
	Common Stock							Common Stock			
	Shares	Amount	Treasury	Additional Paid-in Capital	Retained Earnings (Deficit)	Total Stockholders' Equity	Preferred Stock	Shares	Amount	Equity-based Compensation	Total Mezzanine Equity
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income taxes	—	—	—	—	—	—	—	134	—	(2,961)	(2,961)
Adjustment of minority ownership puttable shares to redemption value	—	—	—	2,722	—	2,722	—	—	(2,722)	—	(2,722)
Adjustment of equity-based compensation to redemption value	—	—	—	(15,602)	—	(15,602)	—	—	—	15,602	15,602
Issuance of common stock	7,500	150	—	149,855	—	150,005	—	—	—	—	—
Shares repurchased with reverse stock split	—	—	(4)	—	—	(4)	—	—	—	—	
Equity-based compensation	—	—	—	—	—	—	—	—	—	25,756	25,756
Balances, December 31, 2023	63,873	$1,283	$(4,582)	$1,034,144	$267,368	$1,298,213	$ —	2,403	$59,988	$126,966	$186,954

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

BKV Corporation

Notes to the Consolidated Financial Statements

Note 1 — Business and Basis of Presentation

Business

BKV Corporation ("BKV Corp") was formed on May 1, 2020 and is a corporation registered with the State of Delaware. BKV Corp is a growth driven energy company focused on creating value for its shareholders through organic development of its properties, as well as accretive acquisitions. BKV Corp's core business is to produce natural gas from its owned and operated upstream businesses.

The majority shareholder of BKV Corp is Banpu North America Corporation ("BNAC"). BKV Corp's ultimate parent company is Banpu Public Company Limited, a public company listed in the Stock Exchange of Thailand. As of April 29, 2024, the date these consolidated financial statements were available to be issued, BNAC owned 96.4% of BKV Corp's shares. The remaining 3.6% of shares of common stock of BKV Corp were owned by non-controlling members of management, members of the Board of Directors ("Directors"), and employee and non-employee shareholders who hold shares with contingent put rights that may be exercised according to conditions stipulated in the agreement among these shareholders, BNAC, and BKV Corp (the "Stockholders' Agreement").

Basis of Presentation

The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") and include the accounts for BKV Corp's wholly owned subsidiaries. Prior years' financial statement amounts have been reclassified in certain cases to conform with the presentation of the consolidated financial statements for the year ended December 31, 2023. As of December 31, 2022, these amounts included current and noncurrent commodity derivative assets, which were reclassified out of other current assets and other noncurrent assets, respectively, on the consolidated balance sheets. In addition, for the years ended December 31, 2022 and 2021, other operating expenses were reclassified out of lease operating and workover expenses on the consolidated statements of operations.

Together, BKV Corp and its wholly owned subsidiaries are referred to collectively as "BKV" or the "Company." All intercompany balances and transactions between these entities have been eliminated within the consolidated financial statements. Current and deferred income taxes and related tax expense have been determined based on the stand-alone results of BKV by applying the separate return method to BKV's operations as if it were a separate taxpayer.

Reverse Stock Split

On October 30, 2023, the Company completed a one-for-two reverse stock split. As a result of the reverse stock split, every two shares of outstanding common stock were combined and now represent one share of common stock, and fractional shares were paid out in cash to the common stockholders, which amounted to an immaterial amount. No fractional shares were issued in connection with the reverse stock split.

Following the reverse stock split, the Company's authorized capital stock consists of 300,000,000 shares of common stock, $0.01 par value per share, of which 66,275,866 shares were issued and outstanding, and 80,000,000 shares of preferred stock, $0.01 par value per share, of which no shares were issued and outstanding. All shares of common stock issuable upon exercise of equity awards, as well as the applicable exercisable prices and weighted average fair value of such equity awards, and per share amounts contained throughout these consolidated financial statements have been retroactively adjusted. See *Note 12 — Equity-Based Compensation and Note 18 — Earnings Per Share* for further discussion and analysis.

Liquidity

As of December 31, 2023, the Company held $165.1 million of cash, cash equivalents, and restricted cash. The Company's working capital deficit as of December 31, 2023 was $100.1 million, which was primarily driven by the current portion of long-term debt of $112.4 million, borrowings under the Company's credit facilities of $127.0 million, and contingent consideration payable of $ 20.0 million. For the year ended December 31, 2023, the Company's cash flows from operations was $123.1 million. The Company intends to make the payments related to the current portion of long-term debt and the contingent consideration payable with cash flows from operations. The Company believes cash flows provided from operations and borrowings under its credit facilities are sufficient to meet cash requirements for the next twelve months and thereafter. As of the date these consolidated financial statements were available to be issued, the Company paid the $20.0 million of contingent consideration payable. The Company also sold call options with a counterparty and received a premium of $23.5 million and early terminated a portion of its derivative contracts and received cash on the gain of $13.3 million. For further discussion on the derivative transactions, see *Note 7 — Derivative Instruments*.

During the first half of 2023, natural gas prices decreased significantly from previous periods, which was the primary cause for the Company to either waive, amend or include additional financial debt covenants in the Company's credit facilities. Additionally, the Company's reduced cash flow from operations could cause the Company not to meet its current and noncurrent financial obligations based on current forecasts. To alleviate these conditions the Company's ultimate parent, Banpu Public Company Limited, has agreed to provide funding to allow the Company to meet its financial obligations through June 30, 2025, if necessary. In addition, on September 27, 2023, BNAC made a capital contribution to the Company of $150.0 million in exchange for purchasing 7,500,000 shares of BKV common stock, pursuant to the requirements of the existing stockholders' agreement. Subsequently, on September 29, 2023, the Company's lenders agreed to amend the Term Loan Credit Agreement and the Revolving Credit Agreement (each as defined and further described in the Annual Financial Statements) to: (i) remove the Company's maximum total net leverage ratio covenant and minimum consolidated fixed charge ratio covenant; (ii) insert the following covenants: (a) maximum debt service coverage ratio, which must be greater than 1.05 to 1.00 at the end of each fiscal quarter and (b) minimum net indebtedness to equity, which must be less than 1.50 to 1.00 at the end of each fiscal quarter; and (iii) require a certain amount of cash to be held in a restricted debt service bank account, which is held as restricted cash in the consolidated balance sheets. To fund the debt service bank account, the Company used $138.3 million of the $150.0 million capital contribution from BNAC.

Note 2 — Summary of Significant Accounting Policies

Significant Judgments and Accounting Estimates

The preparation of these consolidated financial statements in accordance with GAAP for the periods presented requires Company management to make estimates using assumptions and judgments considered reasonable, which affect the consolidated financial statements and accompanying notes. Actual results could differ from those estimates. Estimates which are particularly significant to the Company's consolidated financial statements include: (i) estimates of proved hydrocarbon reserves used in calculating depletion; (ii) estimates of unpaid revenues and unbilled costs; (iii) future cash flows from developed natural gas properties used in impairment assessments; (iv) valuation of commodity derivative instruments; (v) the estimation of asset retirement obligations; (vi) assignment of fair value to assets acquired and liabilities assumed in connection with acquisitions that are considered business combinations and allocating purchase price in connection with acquisitions that are considered asset acquisitions; (vii) valuation of minority ownership puttable shares; (viii) valuation of the Company's common stock relative to the grant date fair value of equity-based compensation; (ix) valuation of market-based performance conditions; (x) valuation of contingent consideration associated with certain acquired assets; and (xi) valuation of deferred income tax assets. While Management is not aware of any significant revisions to any of its current estimates, there will likely be future revisions to its estimates resulting from matters such as revisions in estimated oil and natural gas volumes, changes in ownership interests, payouts, joint venture audits, re-allocations by purchasers or pipelines, or other corrections and adjustments common in the oil and natural gas industry, many of which require retroactive application. These types of adjustments cannot be currently estimated and will be recorded in the period in which the adjustment occurs.

BKV Corporation

Notes to the Consolidated Financial Statements

Principles of Consolidation

These consolidated financial statements include the accounts of BKV Corp and its wholly owned subsidiaries. Accordingly, all intercompany balances and transactions between these entities have been eliminated within the consolidated financial statements. Undivided interests in natural gas properties and midstream assets are consolidated on a proportionate basis.

Comprehensive Income (Loss)

The Company did not have any other comprehensive income (loss) for the years ended December 31, 2023, 2022, and 2021. As such, net income (loss) and comprehensive income (loss) are the same for the periods presented.

Acquisitions

Business Combinations

If the assets acquired and liabilities assumed constitute a business, the transaction is accounted for as a business combination. This method requires the recognition of the acquired identifiable assets, assumed liabilities and any non-controlling interest in the companies acquired at their fair value.

The value of the purchase price may be finalized up to a maximum of one year from acquisition date.

The acquirer shall recognize goodwill at the acquisition date, being the excess of:

- The consideration transferred, the amount of non-controlling interests and, in business combinations achieved in stages, the fair value at acquisition date of the investment previously held in the acquired company;
- Over fair value at acquisition date of acquired identifiable assets and assumed liabilities.

Factors giving rise to goodwill generally include operational synergies that are anticipated as a result of the business combination and growth expected to result in economic benefits from access to new customers and markets. If the consideration transferred is lower than the fair value of acquired identifiable assets and assumed liabilities, an additional analysis is performed on the identification and valuation of the identifiable elements of the assets and liabilities. After having completed such additional analysis, including, if any, adjustments to provisional amounts recognized during the twelve months following the acquisition, any residual negative goodwill is recorded as a bargain purchase gain in the consolidated statements of operations. Subsequent changes to the fair value of contingent consideration are recorded in the other income (expense) section of the consolidated statements of operations.

Asset Acquisitions

When substantially all of the gross assets acquired are concentrated in a single identifiable asset, or a group of similar identifiable assets, the acquisition is treated as an asset acquisition.

The Company accounts for asset acquisitions by performing purchase price allocations wherein the total transaction value is determined by aggregating the base purchase price, certain closing adjustments, and contingent consideration, if any. The total transaction value is then allocated to the acquired assets pro-rata based on their fair values. This allocation may cause identified assets to be recognized at amounts that are greater than their fair values. However, “non-qualifying” assets, which include financial assets and other current assets, should not be assigned an amount greater than their fair value. The determination of fair values of assets acquired requires the Company to make estimates and use valuation techniques. The transaction costs associated with asset acquisitions are capitalized as part of the assets acquired. Subsequent changes to the fair value of contingent consideration are recorded in the other income (expense) section of the consolidated statements of operations.

Cash and Cash Equivalents

Cash represents cash deposits held at financial institutions. Cash equivalents include short-term highly liquid investments of sufficient credit quality that are readily convertible to known amounts of cash and have original maturities of three months or less.

Restricted Cash

As of December 31, 2023, restricted cash includes amounts to fund the debt service reserve account, which is equal to the current portion of the Term Loan Credit Agreement plus accrued interest to comply with the Company's financial covenant under the Term Loan Credit Agreement. The following table provides a reconciliation of cash, cash equivalents, and restricted cash to amounts shown in the consolidated statements of cash flows:

	December 31,	
(in thousands)	**2023**	**2022**
Cash and cash equivalents	$ 25,407	$153,128
Restricted cash	139,662	—
Cash, cash equivalents, and restricted cash	$165,069	$153,128

Inventory

Inventories are stated at the lower of cost or net realizable value. The cost of inventories is based upon the average cost method.

Income Taxes

The Company accounts for income taxes under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Under this method, the Company determines deferred tax assets and liabilities on the basis of the differences between the financial statement and tax bases of assets and liabilities by using enacted tax rates in effect for the year in which the differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date.

The Company regularly reviews its deferred tax assets for recoverability and establishes a valuation allowance if it is more likely than not that some portion, or all, of a deferred tax asset will not be realized. The determination as to whether a deferred tax asset will be realized is made on a jurisdictional basis and is based on both positive and negative evidence. This evidence includes historic taxable income, projected future taxable income, the expected timing of the reversal of existing temporary differences, and the implementation of tax planning strategies.

The Company records uncertain tax positions on the basis of a two-step process in which (i) the Company determines whether it is more-likely-than-not that the tax positions will be sustained on the basis of the technical merits of the position and (ii) for those tax positions that meet the more-likely-than-not recognition threshold, the Company recognizes the largest amount of tax benefit that is more than 50 percent likely to be realized upon ultimate settlement with the related tax authority.

The Company evaluates its tax positions that have been taken or are expected to be taken on income tax returns to determine if an accrual is necessary for uncertain tax positions. The Company recognizes interest and penalties as a component of tax expense. Refer to *Note 17 — Income Taxes* for further discussion.

Natural Gas Properties

The Company uses the successful efforts method of accounting for natural gas producing activities. Costs to acquire mineral interests in natural gas properties, to drill and equip exploratory leases that find proved reserves, and to drill and equip development leases and related asset retirement costs are capitalized. Costs to drill exploratory wells are capitalized, or suspended, pending determination of whether the wells have proved reserves. If the Company determines the wells do not have proved reserves, the costs are charged to expense. For exploratory wells that find reserves that cannot be classified as proved when drilling is completed, costs continue to be capitalized as suspended exploratory drilling costs if there have been sufficient reserves found to justify completion as a producing well and sufficient progress is being made in assessing the reserves and the economic and operational viability of the project. If the Company determines that future appraisal drilling or development activities are unlikely to occur, associated suspended exploratory well costs are expensed. In some instances, this determination may take longer than one year. There were no exploratory wells capitalized pending determinations of whether the wells have proved reserves as of December 31, 2023 and 2022. Geological and geophysical costs, including seismic studies and costs of carrying and retaining unproved properties, are charged to expense as incurred. The Company capitalizes interest on expenditures for significant exploration and development projects that last more than six months while activities are in progress to bring the assets to intended use. For the years ended December 31, 2023, 2022, and 2021, the Company had no capitalized interest costs. Costs incurred to maintain wells and related equipment are charged to expense as incurred. Capitalized amounts attributable to developed gas properties are depleted by the unit-of-production method over proved developed and undeveloped reserves.

The process of estimating natural gas, NGL, and oil reserves is complex and requires significant subjective decisions in the evaluation of all available geological, engineering, and economic data. These estimates are based on studies performed by the Company’s internal engineering function and a third party reserve engineer.

Upon certain triggering events, capitalized costs related to proved gas properties, including wells and related support equipment and facilities, are evaluated for impairment by comparing the associated net capitalized cost to undiscounted future cash flows on a field by field basis. If undiscounted future cash flows are insufficient to recover the net capitalized costs related to proved properties, then the Company recognizes an impairment charge in its results of operations equal to the difference between the net capitalized costs related to proved properties and their estimated fair values. Estimating the fair value of the natural gas properties includes discounting the future net cash flows of the natural gas properties to arrive at a single amount. Significant assumptions included in the discounted cash flow model include natural gas properties reserves, estimated future operating and development cost, expectations of future commodity prices and a market based weighted average cost of capital discount rate. The Company had no impairment of proved properties during the years ended December 31, 2023, 2022, and 2021.

Undeveloped natural gas properties are tested for impairment on a regular basis, based on the results of the exploratory activity and management’s evaluation. In the event of a discovery, the undeveloped natural gas properties are transferred to developed natural gas properties at net book value as soon as proved reserves are recognized. During the years ended December 31, 2023, 2022, and 2021, the Company recognized no impairments related to undeveloped natural gas properties.

Midstream Assets

Midstream assets are recorded at historical cost, less depreciation. Hydrocarbon transportation assets (midstream assets) are depreciated using the straight-line method over 25 years for compressor and meter stations, and 40 years for pipelines. Routine maintenance and repairs are charged to operating expenses as incurred. Realization of the carrying value of midstream assets is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the assets, including any disposal value, is less than the carrying amount of the assets. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. An estimate of fair value is based on discounted future net operating cash flows related to the assets. There were no impairments recognized during the years ended December 31, 2023, 2022, and 2021.

BKV Corporation

Notes to the Consolidated Financial Statements

Other Property and Equipment

Other property and equipment is stated at cost, net of accumulated depreciation. Cost includes the purchase price and, where relevant, any costs directly attributable to bringing the asset to the location and condition necessary. When significant costs are incurred subsequent to the purchase of the asset that extends the life of the asset, such costs are included in the cost of the applicable asset and depreciated over their respective useful lives. All other subsequent costs are recognized in the consolidated statements of operations as either lease operating and workover expense or general and administrative expense.

Realization of the carrying value of other property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Fair value of other property and equipment is determined using the market approach. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. There were no material impairments recognized during the years ended December 31, 2023, 2022, and 2021.

Depreciation and amortization expense is included within Depreciation, depletion, and amortization on the consolidated statements of operations. Following is a listing of useful lives for other property and equipment:

	Useful Life
Buildings	39 years
Furniture, fixtures, equipment, vehicles, and other	5 years
Computer hardware and software	3 – 5 years
Leasehold improvements	7 – 10 years

Deferred Offering Costs

The Company has capitalized legal and other third party fees directly related to the Company's planned initial public offering ("IPO"). The deferred offering costs will be recorded as a reduction of the proceeds received from the IPO. If the IPO is abandoned or significantly delayed, the deferred offering costs will be expensed. As of December 31, 2023 and 2022, the Company capitalized \$8.9 million and \$6.6 million, respectively, of deferred offering costs, which are included within other noncurrent assets on the consolidated balance sheets.

Asset Retirement Obligations

The Company records the estimated fair value of obligations associated with the retirement of tangible, long-lived assets in the period in which they are incurred. When a liability is initially recorded, the Company capitalizes the cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value, and the capitalized cost is depleted over the useful life of the related asset.

Revisions to estimated asset retirement obligations will result in an adjustment to the related capitalized asset and corresponding liability. Upon settlement of the liability, the Company either settles the obligation for its recorded amount or incurs a gain or loss. The Company's asset retirement obligation relates to the plugging, dismantling, removal, site reclamation, and similar activities of its natural gas properties and midstream assets.

Asset retirement obligations are estimated at the present value of expected future net cash flows and are discounted using the Company's credit adjusted risk free rate. The Company uses unobservable inputs in the estimation of asset retirement obligations that include, but are not limited to: costs of labor, costs of materials, profits on costs of labor and materials, the effect of inflation on estimated costs, and discount rate. Due to the subjectivity of assumptions and the relative long lives of the Company's leases, the costs to

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Notes to the Consolidated Financial Statements

ultimately retire the Company's obligations may vary significantly from prior estimates. Assumptions used in determining estimates are reviewed annually.

Leases

The Company recognizes a right-of-use ("ROU") asset and corresponding lease liability on the consolidated balance sheets for all leases. The Company determines if an arrangement is a lease at inception of the arrangement and if such lease will be classified as an operating lease or a finance lease. As of December 31, 2023 and 2022, all of the Company's leases are accounted for as operating leases. The Company makes use of the practical expedient that permits combining lease and non-lease components.

ROU assets represent the Company's right to use an underlying asset for the lease term and lease liabilities represent the Company's obligation to make lease payments arising from the leases. ROU assets and lease liabilities are recognized at the lease commencement date based on the present value of minimum lease payments over the lease term. Most leases do not provide an implicit interest rate; therefore, the Company uses its incremental borrowing rate based on the information available at the inception date to determine the present value of the lease payments. Lease terms include options to extend the lease when it is reasonably certain that the Company will exercise that option. Lease cost for lease payments is recognized on a straight-line basis over the lease term. Certain leases have payment terms that vary based on the usage of the underlying assets.

Revenue Recognition

The Company recognizes revenue for the transfer of goods or services equal to the amount of consideration that it expects to be entitled to receive for those goods or services. The Company derives the majority of revenues from natural gas, NGL, and oil sales contracts. The contracts specify each party's rights regarding the goods or services to be transferred and contain commercial substance as they impact the Company's consolidated financial statements. A high percentage of associated receivables balance is current, and the Company has not historically entered into contracts with counterparties that pose a credit risk without requiring adequate economic protection to ensure collection. The Company determines revenue recognition through the following five step model:

- Identification of the contract(s) with a customer
- Identification of the performance obligation(s) in the contract
- Determination of the transaction price
- Allocation of the transaction price to the performance obligation(s) in the contract
- Recognition of revenue when or as performance obligation(s) are satisfied

Natural Gas, NGLs, and Oil Sales

Sales of natural gas, NGLs, and oil are recognized when the Company satisfies a performance obligation by transferring control of its product to its customers. Such sales amounts are based on an estimate of the volumes delivered at estimated prices as determined by the applicable sales agreement, which is variable based on commodity pricing. The Company estimates its sales volumes based on company-measured volume readings. Natural gas, NGL, and oil sales are adjusted in subsequent periods based on data received from the Company's purchasers with the associated payment that reflects actual volumes and prices received. The data and payment are typically received by the Company within two months of transfer of control to the purchaser. Historically, the difference between estimated and actual sales revenues have not been material. Under the Company's sales contracts, the Company invoices customers after its performance obligations have been satisfied, at which point payment is considered unconditional. Until payment for the performance obligation has occurred, the Company records an accounts receivable on its consolidated balance sheets.

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Notes to the Consolidated Financial Statements

Typically, the Company's natural gas, NGL, and oil sales contracts define the price as a formula based on the average market price, as specified on set dates each month, for the specific commodity during the month of delivery. Given the industry practice to invoice customers the month following the month of delivery and the Company's payment terms which are typically within two months of control transfer, no significant financing component is included within the contracts.

Under the Company's natural gas sales contracts, it delivers natural gas to the purchaser at an agreed upon delivery point for a specified index price adjusted for pricing differentials. To deliver natural gas to the agreed upon delivery point, the Company or other third parties gather, compress, process and transport the Company's natural gas. The Company maintains control of the natural gas during gathering, compression, processing, and transportation. Upon delivery of the product, the Company transfers control and recognizes revenue based on the contract price. In this scenario, the Company is the principal, and revenues are recognized on a gross basis or based on the contract price.

The Company also enters into certain contracts for gathering and transportation of natural gas, NGL and oil products to deliver the products to customers. Fees incurred prior to control transfer are considered shipping and handling costs and are classified as gathering and transportation expense. Fees incurred after control transfer are included as a reduction to the transaction price. In this scenario, the Company is the agent, and revenues are recognized on a net basis.

For the years ended December 31, 2023, 2022, and 2021, the impact of any natural gas imbalances was not significant.

Midstream Revenues

Non-operated and operated midstream revenues are recognized when services are rendered based on quantities transported and measured according to the underlying contracts. The Company records midstream revenues based on volumes transported at stated contractual rates. The Company estimates its non-operated midstream revenue volumes based on third party data with respect to its proportionate share of non-operated volumes and actual gross volumes for operated midstream revenues. Non-operated midstream revenues are adjusted in subsequent periods based on data received from the operator that reflects actual volumes, which is typically within three months.

Marketing Revenues

In conjunction with certain contracts for the sales of natural gas and NGLs, the Company recognizes its share of net profits related to marketing revenues generated from a profit sharing agreement with a marketer. The contract includes variable components of consideration that are settled upon satisfaction of performance obligations which occurs at the point which control of the natural gas or NGLs is transferred by the purchaser to a third party. Revenues are recognized based on the underlying variable consideration pricing and delivered volumes.

Other Considerations

In addition to revenues from natural gas, NGL, and oil contracts from the Company's operated assets, BKV Corp entered into joint operating agreements as a non-operator for the sale of hydrocarbons through other operators. As a non-operator, BKV Corp recognizes revenue based on the actual (known) consideration that is obtained from the operator because BKV Corp does not have visibility into the terms of the sale. Consequently, non-operated revenue is recorded when the data is available.

The recognition of gains or losses on derivative instruments is not considered revenue from contracts with customers. The Company may use financial contracts accounted for as derivatives as economic hedges to manage price risk associated with normal sales or in limited cases may use them for contracts the Company intends to physically settle but that do not meet all of the criteria to be treated as normal sales.

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Transaction Price Allocated to Remaining Performance Obligations

For the Company’s product sales that have a contract term greater than one year, the Company utilized the practical expedient, which does not require the disclosure of the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under the Company’s product sales contracts, each unit of product delivered to the customer represents a separate performance obligation; therefore, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required. For the Company’s product sales that have a contract term of one year or less, the Company utilized the practical expedient, which does not require the disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

Contract Costs

Costs to obtain a contract are generally immaterial but the Company has elected the practical expedient to expense these costs as incurred if the duration of the contract is one year or less.

Please refer to *Note 10 — Revenue from Contracts with Customers* for additional disclosure.

Lease Operating and Workover Expense

Lease operating expenses represent certain field employees’ salaries, salt water disposal, repairs and maintenance, and other standard operating expenses. Lease operating expenses are expensed as incurred.

Workover expenses include those costs incurred to perform more substantial maintenance or remedial treatments on a well to enhance production. These costs are also expensed as incurred.

Derivative Financial Instruments

The Company enters into commodity derivative instruments to reduce the effect of price volatility on a portion of the Company’s future natural gas and NGL production. These activities may prevent the Company from realizing the full benefits of price increases above the levels of the derivative instruments on a portion of its future natural gas and NGL production. The commodity derivative instruments are measured and recorded at fair value and included in the consolidated balance sheets. Such fair values are calculated based on the market approach, which uses industry standard models, assumptions, and inputs. These assumptions and inputs are substantially observable in active markets throughout the full term of the instruments and include market price curves, contract terms and prices, credit risk adjustments, implied market volatility, and discount factors. The Company does not hold or issue derivative financial instruments for trading purposes. In addition, the Company has not designated any of its derivative contracts as fair value or cash flow hedges. As such, hedge accounting does not apply and any unsettled net gains and losses, or changes in the fair values of the derivative instruments, are included within derivative gains (losses), net in the consolidated statements of operations. The Company’s cash flows are only impacted when the actual settlements under the commodity derivative contracts result in making or receiving a payment to or from the counterparty. These settlements under the commodity derivative contracts are reflected as operating activities in the Company’s consolidated statements of cash flows.

Credit risk is defined as the risk of a counterparty to a contract failing to perform or pay the amounts due. The Company is exposed to credit risks in its operating and financing activities. The Company’s maximum exposure to credit risk is generally limited to the aggregate fair value of the outstanding contracts in an unrealized gain position offset by any collateral posted with the counterparty. The Company’s counterparties are primarily with commercial banks and financial service institutions with high credit quality and are subject to master netting agreements; therefore, the risk of nonperformance by the counterparties is low. Accordingly, adjustments for counterparty credit risk are immaterial.

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Notes to the Consolidated Financial Statements

Accounts Receivable and Allowance for Expected Credit Losses

The Company's receivables consist mainly of trade receivables from contracts with customers from commodity sales. Accounts receivable from contracts with customers are recorded when the right to consideration becomes unconditional, generally when control of the product has been transferred to the customer. The majority of these receivables have payment terms of 60 days or less from when control is transferred. The Company also has joint interest billings due from owners on properties the Company operates. For receivables due from joint interest owners, the Company generally has the ability to withhold future revenue disbursements to recover non-payment of joint interest billings. From an evaluation of the Company's existing credit portfolio, historical credit losses have not been material to the Company and are expected to remain so in the future assuming no substantial changes to the business or creditworthiness of BKV Corp's business partners.

Fair Value of Financial Instruments

Fair value, as defined by the relevant accounting standards, represents the exchange price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The Company determines the fair values of its assets and liabilities that are recognized or disclosed at fair value in accordance with the hierarchy described below:

Level 1 — Quoted and unadjusted prices in active markets for identical assets or liabilities.

Level 2 — Observable inputs other than Level 1 prices such as: (i) quoted prices for similar assets or liabilities in active markets; (ii) quoted prices for identical or similar assets or liabilities in markets that are not active; or (iii) valuations based on pricing models where significant inputs (e.g., interest rates, yield curves, etc.) are observable for the assets or liabilities, are derived principally from observable market data, or can be corroborated by observable market data.

Level 3 — Unobservable inputs, including valuations based on pricing models where significant inputs are not observable and not corroborated by market data. Unobservable inputs are used to the extent that observable inputs are not available and reflect the Company's own assumptions about the assumptions market participants would use in pricing the assets or liabilities. Unobservable inputs are based on the best information available under circumstances which might include the Company's own data.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to fair value measurement requires judgment and may affect the fair value of the assets and liabilities and their placement within fair value hierarchy levels.

Fair values are estimated for the majority of the Company's financial instruments. Estimations of fair value, which are based on principles such as discounting future cash flows to present value, must be weighted by the fact that the value of a financial instrument at a given time may be influenced by the market environment (particularly liquidity) and that subsequent changes in interest rates and exchange rates are not taken into account. The carrying amounts for the Company's financial instruments included in current assets and current liabilities approximates fair value due to the short-term maturities of these instruments. In addition, as of December 31, 2023, the carrying value of the Company's long-term debt approximated the fair value as the applicable interest rates are variable and reflective of current market rates.

The valuation techniques that may be used to measure fair value include a market approach, an income approach, and a cost approach. A market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. An income approach uses valuation techniques to convert future amounts to a single present amount based on current market expectations, including present value techniques, option-pricing models and the excess earnings method. The cost approach is based on the amount that currently would be required to replace the service capacity of an asset (replacement cost). The Company primarily applies the market and income approach for recurring fair value measurements and endeavor to utilize the best available information.

Goodwill

Goodwill represents the excess of the cost of an acquisition over the fair value of the net assets acquired. Impairment may occur if the reporting unit's carrying value exceeds its fair value. The Company has one identifiable operating segment, which represents the Company's reporting unit where goodwill is tested. The Company performs an impairment test for goodwill at least annually or when events and circumstances indicate the carrying value may not be recoverable. In performing the required impairment tests, the Company has the option to first assess qualitative factors to determine if it is necessary to perform a quantitative assessment for goodwill impairment. If the qualitative assessment concludes that it is more-likely-than-not that the fair value of a reporting unit is less than its carrying value, a quantitative assessment is performed. The Company's quantitative assessment utilizes present value (discounted cash flow) methods to determine the fair value of the reporting units with goodwill. Determining fair value using discounted cash flows requires considerable judgment and is sensitive to changes in underlying assumptions and market factors. Key assumptions relate to revenue growth, projected operating income growth, terminal values, and discount rates. If current expectations of future growth rates and margins are not met, or if market factors outside of the Company's control, such as factors impacting the applicable discount rate, or economic or political conditions in key markets change significantly, then goodwill of the reporting unit may be impaired. Management determined there were no circumstances indicating the carrying value of goodwill may not be recoverable during the years ended December 31, 2023, 2022, and 2021. Therefore, there have been no impairments recorded related to goodwill as the results of the annual quantitative impairment test indicated the fair value of the assets of the reporting unit to be greater than the carrying value during the years ended December 31, 2023, 2022, and 2021.

Equity-Based Compensation

The Company recognizes compensation cost related to equity-based awards in its consolidated financial statements on a straight-line basis based on estimated grant date fair value over the applicable vesting or service period. Equity-based compensation awards which ultimately settle in cash are accounted for as liabilities, and awards which are contingently settled in cash or shares of the Company's common stock are accounted for as mezzanine equity. Mezzanine equity classified awards which are considered probable of becoming redeemable are carried on the consolidated balance sheets at the greater of redemption value or initial carrying value. Changes in the redemption value of the awards result in a transfer from stockholders' equity to mezzanine equity on the consolidated balance sheets of the Company.

The Company is authorized to grant equity-based compensation in the form of restricted stock units which include service conditions, and performance-based restricted stock units, which include service conditions, market performance conditions, and non-market performance conditions. The grant date fair value is determined based on the components of the award and utilize the estimated fair market value of common stock on the grant date, Monte Carlo simulations, and the estimated fair market value of common stock on the grant date coupled with probability assessments relative to the satisfaction of non-market performance conditions.

Forfeitures are estimated and recognized over the applicable vesting or service period and are re-evaluated at the end of each reporting period. The Company's equity-based compensation is discussed further in *Note 12 — Equity-Based Compensation*.

Treasury Stock

The Company recognizes purchases of its own stock as a reduction to stockholders' equity or mezzanine equity in the consolidated balance sheets using the cost method. Shares are held until authorized for redistribution by the Company's Board of Directors.

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Equity Method Investments

The Company applies the equity method of accounting to its investments over which it does not have the power to direct the activities that most significantly impact the investment's economic performance. The Company's judgment regarding the level of influence over its equity method investments includes considering key factors such as the Company's ownership interest, representation on the investee's board of directors (the "JV Board"), and participation in the policy-making decisions of equity method investee. The carrying value of the Company's equity method investments is recorded in investment in joint venture on the consolidated balance sheets. The Company's pro-rata share of earnings in equity method investments is recorded in earnings from equity affiliate in the consolidated statements of operations.

The Company evaluates its investment in the equity method investee for impairment whenever events or changes in circumstances indicate that the carrying value of its investment may have experienced an "other-than-temporary" decline in value. If such conditions exist, the Company compares the estimated fair value of the investment to its carrying value to determine if an impairment is indicated. If impairment is indicated, the Company then determines whether the impairment is "other-than-temporary" based on its assessment of all relevant factors, including consideration of the Company's intent and ability to retain its investment.

Net Income (Loss) Per Common Share

Basic net income (loss) per common share for each period is calculated by dividing net income (loss) available to common shareholders by the basic weighted average number of shares outstanding during the period. Diluted net income (loss) per common share is calculated by dividing net income (loss) available to common stockholders of the Company by the diluted weighted average number of common shares outstanding for the respective period. Diluted weighted average number of common shares outstanding and the dilutive effect of potential common shares is calculated using the treasury stock method for restricted stock units ("RSUs") and the if-converted method for preferred stock. The Company includes potential shares of common stock for performance-based restricted stock units ("PRSUs") in the calculation of diluted weighted average shares outstanding based on the number of common shares that would be issuable if the end of the reporting period was also the end of the performance period. During periods in which the Company incurred a net loss, diluted weighted average common shares outstanding were equal to basic weighted average of common shares outstanding because the effects of all potential common shares was anti-dilutive.

Business Segment Information

The Company is organized and managed and identified as one operating segment and one reportable segment. The Company measures financial performance on a consolidated basis with all operating revenues and income from operations generated in, and all assets based in the United States.

Recent Accounting Pronouncements

In December 2023, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2023-09 *Income Taxes* (Topic 740). This ASU provides further transparency through enhanced disclosure of specific categories around the income tax rate reconciliation, and disaggregation of income taxes paid, income (loss) from continuing operations, and income tax expense (benefit) by federal, state, and foreign jurisdictions, among others. The amendments in this update are effective for annual periods beginning after December 15, 2024, and should be applied prospectively. Management is currently evaluating the impact of this guidance, but does not expect this update to have a material impact on the Company's financial statements.

In November 2023, the FASB issued ASU 2023-07,*Segment Reporting* (Topic 280). This update provides enhanced disclosures of significant segment expenses that are provided to the chief operating decision maker used to assess segment performance and determine how to allocate resources. The amendments in this update are effective for the year ended December 31, 2024 and interim periods beginning January 1,

2025. Management believes that this updated guidance will not have a material impact on the Company's financial statements, as the Company is currently organized, managed, and identified as one operating and reportable segment.

In August 2023, the FASB issued ASU 2023-05 — *Business Combinations — Joint Venture Formations* (Topic 805). This update applies to the formation of entities that meet the definition of a joint venture (or a corporate joint venture) and addresses how a joint venture should recognize contributions received upon its formation, and measure its assets and liabilities at fair value on the date the joint venture is formed. This guidance is effective for joint ventures formed beginning January 1, 2025 with early adoption permitted. This amendment would only impact the Company upon adoption or in the future if the Company entered into a joint venture.

Note 3 — Acquisition

Exxon Barnett Acquisition

On May 18, 2022, the Company entered into an agreement to acquire certain operated and non-operated interests in proved reserves and certain midstream support assets (the "Purchase and Sale Agreement") in the Barnett formation (the "2022 Barnett Assets") from XTO Energy, Inc. and Barnett Gathering LLC, subsidiaries of Exxon Mobil Corporation (collectively, "Seller"), for $750.0 million (subject to working capital and other adjustments) and additional contingent payments totaling $50.0 million, if certain pricing thresholds are met in future periods (the "Exxon Barnett Acquisition"). The Company paid a deposit of $75.0 million to the Seller in conjunction with entering into the Purchase and Sale Agreement. The Company closed the transaction on June 30, 2022; the adjusted purchase price, excluding contingent consideration, was $619.4 million, which included the $75.0 million deposit. As of the acquisition date, the fair value of the additional contingent payments was $17.2 million. See *Note 6 — Fair Value Measurements* and *Note 16 — Commitments and Contingencies* for discussion of the fair market value valuation methodology applied to the contingent consideration at the acquisition date and details of the contingent consideration, respectively. The Company funded the cash portion of the consideration with the proceeds from its $570.0 million term loan and the proceeds from the $75.0 million loan from BNAC. Refer to *Note 4 — Debt* and *Note 9 — Related Parties*, respectively, for further information on these loans.

The Exxon Barnett Acquisition was accounted for as a business combination; therefore, the assets acquired and liabilities assumed were recorded based on the respective estimated acquisition date fair values with information available at the time, and the residual difference between the net assets and the purchase price was recorded as a bargain purchase gain in the consolidated statements of operations. A combination of discounted cash flow models and market data was used by a third party specialist, under the direct supervision of management, in determining the fair value of the natural gas properties and midstream assets. Significant inputs into the calculation included future commodity prices, estimated volumes of natural gas, NGL, and oil reserves, expectations for the timing and amount of future development and operating costs, future plugging and abandonment costs, and a risk adjusted discount rate. As of June 30, 2023, the Company completed the purchase price accounting, including the fair market value assessment of the assets acquired and the liabilities assumed from the Exxon Barnett Acquisition, and no further adjustments to the purchase price have been made. The Exxon Barnett Acquisition resulted in a bargain purchase gain, which was primarily caused by the increase in commodity pricing from the date the acquisition was originally negotiated through the closing date. The bargain purchase gain of $170.9 million was recognized net of related income tax expense of $50.6 million, and is included as such on the Company's consolidated statements of operations. The Exxon Barnett Acquisition was made to support the strategic growth of the Company and to achieve operational synergies with pre-existing assets in the Barnett formation. During the year ended December 31, 2022, the Company incurred $5.0 million of acquisition costs, which are included within general and administrative expense on the consolidated statements of operations. The results of operations for the assets acquired in the Exxon Barnett Acquisition since closing on June 30, 2022 are included in the Company's consolidated statements of operations for the year ended December 31, 2022 and include $225.1 million of total revenue and $130.6 million of income from operations.

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The estimated purchase price consideration and fair value of assets acquired and liabilities assumed are as follows (in thousands):

Cash	$ 619,437
Contingent consideration	17,150
Total consideration	$ 636,587
Assets acquired and liabilities assumed:	
Inventory	$ 150
Natural gas properties – developed	657,935
Midstream assets	260,843
Other property and equipment	8,856
Property taxes	(6,296)
Deferred tax liability	(50,569)
Revenues payable	(16,612)
Asset retirement obligations	(46,867)
Total identifiable net assets	$ 807,440
Bargain purchase gain	$(170,853)

Pro Forma Information. The following pro forma financial information represents a summary of the historical consolidated results of operations for the years ended December 31, 2022 and 2021, giving effect to the Exxon Barnett Acquisition as if it had been completed on January 1, 2021. The pro forma financial information is provided for illustrative purposes only and is not intended to represent what the Company's financial position or results of operations would have been had the Exxon Barnett Acquisition occurred on the assumed date, nor does it purport to project the future operating results or the financial position of the Company following the Exxon Barnett Acquisition.

The information below reflects certain nonrecurring and recurring pro forma adjustments that were directly related to the business combination based on available information and certain assumptions that the Company believes are reasonable, including: (i) the increase in depletion and amortization reflecting the relative fair values and production volumes attributable to the Seller's natural gas properties and the revision to the depletion rate reflecting the reserve volumes acquired, (ii) the increase in depreciation expense reflecting the relative fair values attributable to the Seller's midstream assets and revision of useful lives reflecting the Company's estimate thereof, (iii) adjustments to interest expense as a result of the Company's indebtedness incurred to fund the purchase of the 2022 Barnett Assets further described in *Note 4 — Debt* and *Note 9 — Related Parties* for the $570.0 million term loan and $75.0 million related party note, respectively, (iv) increase in accretion expense reflective of the fair market value of asset retirement obligations, (v) increase of general and administrative expense during the year ended December 31, 2021 for transition services provided by the Seller upon acquisition, and a corresponding decrease of general and administrative expenses for the year ended December 31, 2022 for the actual transition service expense incurred by the Company, and (vi) the estimated tax impacts of the pro forma adjustments.

	Year Ended December 31,	
(in thousands)	**2022**	**2021**
Total revenues and other operating income	$1,253,623	$ 820,173
Net income (loss) attributable to BKV Corporation	$ 476,567	$(113,181)

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Note 4 — Debt

The Company's outstanding borrowings consisted of the following:

	December 31,	
(in thousands)	**2023**	**2022**
Credit facilities		
OCBC Credit Facility	$ —	$ 45,000
SCB Credit Facility	31,000	—
Revolving Credit Agreement	96,000	45,000
Term loan		
Current portion of Term Loan Credit Agreement	114,000	114,000
Current portion of unamortized debt issuance costs	(1,627)	(1,999)
Total current debt, net	239,373	202,001
Term Loan Credit Agreement	342,000	456,000
Long-term portion of unamortized debt issuance costs	(2,337)	(3,964)
Total long-term debt, net	339,663	452,036
Total debt, net	$579,036	$654,037

Revolving Credit Facilities

On December 22, 2021, the Company entered into an agreement with respect to a $55.0 million uncommitted credit facility with Oversea-Chinese Banking Corporation Limited (the "Bank"). This agreement provides for a revolving credit facility (the "OCBC Credit Facility") with a limit of $55.0 million. Of the $55.0 million, a maximum of $25.0 million can be used for the issuance of standby letters of credit, and in the absence of outstanding letters of credit, the full $55.0 million is available for cash draw downs. The OCBC Credit Facility is not secured. Advances on the OCBC Credit Facility are required to be repaid upon the earlier of 60 days after the date of the advance, or upon the receipt of a written demand notice from the Bank. Advances from the OCBC Credit Facility must be greater than $1.0 million. Interest on any outstanding advances is payable monthly using the Secured Overnight Financing Rate ("SOFR") plus a credit spread of 0.11% and an interest rate margin of 2.0%. On December 29, 2023, the Company repaid the full $50.0 million of outstanding borrowings on the OCBC Credit Facility, including accrued interest, and concurrently terminated the OCBC Credit Facility.

On March 16, 2022, the Company entered into an agreement with Standard Chartered Bank, which provides term loans and letters of credit (the "SCB Credit Facility") with a limit of $25.0 million. On February 7, 2023, the Company and Standard Chartered Bank agreed to increase the limit of the SCB Credit Facility from $25.0 million to $50.0 million. Of the $50.0 million, $35.0 million is available for cash draw downs, and in the absence of outstanding cash draw downs, the full $50.0 million is available for letters of credit. The SCB Credit Facility is an unsecured facility committed through August 31, 2024. Interest is agreed upon at the time of each cash draw down. Cash draw downs, plus all applicable interest are payable at one, three, six, or twelve months from the date of the advance and as of December 31, 2023, the variable interest rate was 7.37%. Of the outstanding balance of $31.0 million as of December 31, 2023, $16.0 million is due on June 11, 2024, and $15.0 million is due on June 18, 2024. On March 5, 2024, the Company drew down $4.0 million, which is due on June 3, 2024. As of December 31, 2023, the SCB Credit Facility had outstanding letters of credit amounting to $ 12.2 million, of which $3.5 million was issued on behalf of BKV-BPP Retail, LLC, a related party. See *Note 9 — Related Parties* for further information. The $3.5 million letter of credit issued on behalf of BKV-BPP Retail, LLC expired on January 30, 2024, and was replaced with cash by BKV-BPP Power.

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Revolving Credit Agreement

On August 24, 2022, the Company entered into an agreement with Bangkok Bank Public Company Limited (New York Branch), which provides for a revolving credit facility (the "Revolving Credit Agreement") with a limit of $100.0 million. The Revolving Credit Agreement is an unsecured facility committed through September 30, 2027. Cash draw downs and all applicable interest is payable at one, three, or six months from the date of the advance using SOFR plus a credit spread of 0.10% and an interest rate margin of 4.75%. The interest period is determined by the Company at the time of the advance and as of December 31, 2023, the variable interest rate was 10.21%. Of the outstanding balance of $96.0 million, $19.0 million was paid down on April 10, 2024, including accrued interest, and $35.0 million is due on June 27, 2024 and $27.0 million is due on June 28, 2024. On March 6, 2024, the Company paid down $15.0 million of the $96.0 million, including accrued interest, and on March 19, 2024 and March 20, 2024, the Company drew down $5.0 million per day from the Revolving Credit Agreement, of which $1.0 million was paid down on April 10, 2024. The remaining balance of these draws are both due on June 20, 2024.

In August 2022, the Company paid debt issuance costs of $1.1 million, which was recorded in other current and noncurrent assets in the consolidated balance sheets. As of December 31, 2023 and 2022, $0.8 million and $1.0 million, respectively, remained unamortized.

Term Loan Credit Agreement

On June 16, 2022, the Company entered into an agreement with a syndicate of lenders and Bangkok Bank Public Company Limited (New York Branch), as the administrative agent, whereby the Company can borrow up to $600.0 million in the aggregate, in the form of multiple term loans during the period commencing with the effective date and ending six months thereafter (the "Term Loan Credit Agreement"). The term loans under the Term Loan Credit Agreement must be equal to or greater than $5.0 million and amounts repaid by the Company in respect to the term loans may not be re-borrowed under the Term Loan Credit Agreement. Once drawn, the term loans are required to be repaid annually in five equal installments; installment payments are due on each anniversary of the original draw for the respective term loan. The term loans are not secured. On June 30, 2022, the Company drew a term loan of $570.0 million to fund the Exxon Barnett Acquisition. Interest is payable semi-annually in June and December using SOFR plus a credit spread of 0.10% and an interest rate margin of 4.75%. As of December 31, 2023, the interest rate of on this outstanding balance was 10.06%. The proceeds of the term loans must be used to finance the Exxon Barnett Acquisition. See *Note 3 — Acquisition.* The Company paid debt issuance costs of $6.6 million, which was recorded in current portion of long-term debt, net and long-term debt, net in the consolidated balance sheets. As of December 31, 2023 $4.0 million remained unamortized.

As of December 31, 2023, the weighted average interest rate on the Company's short-term borrowings of $241.0 million was 9.78%.

The Term Loan Credit Agreement and the Revolving Credit Agreement require the Company to maintain certain financial covenants at the end of each fiscal quarter, including (i) the asset coverage ratio to be no less than 2.00 to 1.00, (ii) the maximum debt service coverage ratio to be no less than 1.05 to 1.00, and (iii) the minimum net indebtedness to equity ratio to be no more than 1.50 to 1.00. The Term Loan Credit Agreement also requires the Company to hold a certain amount of cash held in a restricted debt service bank account equal to the current portion of the Term Loan Credit Agreement plus accrued interest. The Revolving Credit Agreement requires the Company to have an accounts receivable balance from its largest purchaser that exceeds the outstanding balance on the Revolving Credit Agreement. As of December 31, 2023, the Company was in compliance with all covenants of the Term Loan Credit Agreement and the Revolving Credit Agreement.

On December 26, 2023, the lenders under the Revolving Credit Agreement agreed to waive compliance with respect to the minimum marketer receivables covenant for up to $40.0 million of our credit facility borrowings under the Revolving Credit Agreement with total borrowings not to exceed $100.0 million. This waiver is effective through July 31, 2024.

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Note 5 — Natural Gas Properties & Other Property and Equipment

Accumulated depreciation, depletion, and amortization for developed natural gas properties as of December 31, 2023 and 2022 was $560.0 million and $363.8 million, respectively. Depreciation, depletion, and amortization expense for developed natural gas properties for the years ended December 31, 2023, 2022, and 2021 was $196.1 million, $96.5 million, and $78.1 million, respectively.

Midstream assets consisted of the following:

	December 31,	
(in thousands)	**2023**	**2022**
Compressor station	$ 37,280	$ 37,130
Meter station	721	654
Pipelines	280,854	279,325
Total	318,855	317,109
Accumulated depreciation	(19,399)	(11,951)
Midstream assets, net	$299,456	$305,158

Depreciation expense on midstream assets was $7.5 million, $4.5 million, and $1.3 million for the years ended December 31, 2023, 2022, and 2021, respectively.

Other property and equipment consisted of the following:

(in thousands)	December 31,	
	2023	**2022**
Carbon capture, utilization, and sequestration	$ 59,142	$ —
Buildings	15,707	16,788
Furniture, fixtures, equipment, and vehicles	15,101	14,368
Computer software	4,844	4,844
Land	3,090	3,090
Leasehold improvements	1,685	1,627
Construction in process	76	9,845
Total	99,645	50,562
Accumulated depreciation	(15,710)	(10,697)
Other property and equipment, net	$ 83,935	$ 39,865

Depreciation expense for other property and equipment was $5.7 million, $4.4 million, and $2.8 million for the years ended December 31, 2023, 2022, and 2021, respectively.

Note 6 — Fair Value Measurements

As the Company uses the market approach to determine the fair value of its derivative instruments, these fair values are also compared to the values given by counterparties for reasonableness. Since natural gas and NGL swaps do not include optionality and therefore generally have no unobservable inputs, they are classified as Level 2. The Company factors its own non-performance risk into the valuation of derivatives using current published credit default swap rates. As of December 31, 2023 and 2022, the impact of the non-performance risk adjustment to the Company's fair value of commodity derivative liabilities was $1.0 million and $1.7 million, respectively.

Contingent consideration, minority ownership puttable shares, equity-based compensation, and assets acquired and liabilities assumed in the Exxon Barnett Acquisition are measured at fair value using Level 3

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valuation techniques. There were no transfers between fair value levels during the years ended December 31, 2023, 2022, and 2021.

The following tables set forth, by level within the fair value hierarchy, the financial assets and liabilities that were accounted for at fair value on a recurring basis:

	As of December 31, 2023		
	Fair Value Measurements Using:		
(in thousands)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Financial assets			
Derivative instruments	$ 102,547	$ —	$102,547
Financial liabilities			
Derivative instruments	—	—	—
Contingent consideration	—	29,676	29,676
Mezzanine equity			
Minority ownership puttable shares	—	59,988	59,988
Equity-based compensation	—	126,966	126,966

	As of December 31, 2022		
	Fair Value Measurements Using:		
(in thousands)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Financial assets			
Derivative instruments	$ 3,467	$ —	$ 3,467
Financial liabilities			
Derivative instruments	49,484	—	49,484
Contingent consideration	—	88,051	88,051
Mezzanine equity			
Minority ownership puttable shares	—	62,712	62,712
Equity-based compensation	—	89,171	89,171

The contingent consideration was generated from the 2019 acquisition of interest in proved reserves and related upstream assets in the Barnett formation from Devon Energy Corporation (the "Devon Barnett Acquisition") and the Exxon Barnett Acquisition. The fair value of the contingent consideration as of December 31, 2023 and 2022 represents management's best estimate if a third party were paid to assume the contingency. The fair values were determined using Monte Carlo simulations, which use observable (Level 2) inputs based on forecasted monthly Henry Hub Prices and West Texas Intermediate ("WTI") prices, as applicable, and unobservable (Level 3) inputs. The Exxon Barnett Acquisition and Devon Barnett Acquisition contingencies are described further in *Note 16 — Commitments and Contingencies*.

The minority ownership puttable shares were recorded at fair value upon initial recognition in mezzanine equity on the consolidated balance sheets. The fair market value of the Company's common stock was used to determine the initial carrying value and redemption value of the minority ownership puttable shares in mezzanine equity on the consolidated balance sheets as of December 31, 2023 and 2022. The Company's common stock was valued using both observable (Level 2) and unobservable (Level 3) inputs. The minority ownership puttable shares are further described in *Note 13 — Stockholders' Equity and Mezzanine Equity*.

Equity-based compensation is recorded at fair market value on the grant date. The underlying market condition was valued using the application of Monte Carlo simulations using both observable (Level 2) and

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unobservable (Level 3) inputs. The remaining components of the awards were valued based on the fair market value of the common stock of the Company, which is valued consistent with valuation methodologies described for the minority ownership puttable shares. As of December 31, 2023 and 2022, the fair market values of the Company's market condition and common stock were used to determine the redemption value or fair market value of equity-based compensation in mezzanine equity on the consolidated balance sheets. Equity-based compensation is further described in *Note 12 — Equity-Based Compensation and Note 13 — Stockholders' Equity and Mezzanine Equity.*

All per share amounts for common stock and equity-based compensation have been retrospectively restated to reflect the effect of the reverse stock split. Quantitative data regarding the Company's Level 3 unobservable inputs are as follows:

(in thousands, except per share amounts)	Fair Value	Valuation Technique	Unobservable Input	Range or Actual
Market condition equity-based compensation per share, as of December 31, 2022	$ 35.54	Monte Carlo Simulation	Performance period dividends	3.0% equity capital, annually
Common stock – per share value, as of December 31, 2022[1]	$ 29.54	Enterprise value	Discount rate	10.0% – 11.0%
Contingent consideration, as of December 31, 2022	$ 88,051	Monte Carlo Simulation	Risk free rate[2]	4.8%
			Credit spread	4.8%
			Discount rate	9.6%
Common stock – per share value, as of December 31, 2023[1]	$ 28.25	Enterprise value	Discount rate	11.5% – 12.5%
Contingent consideration, as of December 31, 2023	$ 29,676	Monte Carlo Simulation	Risk free rate[2]	5.2%
			Credit spread	4.7%
			Discount rate	9.9%

(1) The Company uses the midpoint of valuation results when estimating the fair value of common stock.

(2) Represents an observable input.

The table below sets forth the changes in the Company's Level 3 fair value measurements:

(in thousands)	2023	2022	2021
Balance, as of January 1,	$239,934	$226,380	$ 54,853
Contingent consideration – additions through acquisitions	—	17,150	—
Contingent consideration – settled	(20,000)	(65,000)	(65,000)
Minority ownership puttable share activity	(2)	78	511
Grant date fair value of equity-based compensation	22,193	30,765	28,990
Change in fair market value *(all instruments)*	(25,495)	30,561	207,026
Balance, as of December 31,	$216,630	$239,934	$226,380

Note 7 — Derivative Instruments

From time to time, the Company may utilize derivative contracts in connection with its natural gas and NGL operations to provide an economic hedge of the Company's exposure to commodity price risk associated with anticipated future natural gas and NGL production. The derivative contracts outstanding

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as of December 31, 2023 consisted of commodity swaps, basis swaps, and collar agreements, subject to master netting agreements with each individual counterparty. The following table presents gross commodity derivative balances prior to applying netting adjustments recorded in the consolidated balance sheets:

		As of December 31, 2023		
(in thousands)	Balance Sheet Location	Gross Amounts of Assets and Liabilities	Offset Adjustments	Net Amounts of Assets and Liabilities
Current derivative assets	Commodity derivative assets, current	$ 90,540	$ (6,501)	$ 84,039
Noncurrent derivative assets	Commodity derivative assets	18,615	(107)	18,508
Current derivative liabilities	Commodity derivative liabilities, current	6,501	(6,501)	—
Noncurrent derivative liabilities	Other noncurrent liabilities	107	(107)	—

		As of December 31, 2022		
(in thousands)	Balance Sheet Location	Gross Amounts of Assets and Liabilities	Offset Adjustments	Net Amounts of Assets and Liabilities
Current derivative assets	Commodity derivative assets, current	$ 3,719	$ (1,068)	$ 2,651
Noncurrent derivative assets	Commodity derivative assets	816	—	816
Current derivative liabilities	Commodity derivative liabilities, current	50,552	(1,068)	49,484

Collar, Commodity Swap, and Basis Swap Contracts

A commodity collar provides for a price floor and a price ceiling. The floating price for the collar contract is traded for a fixed price when the floating price is not between the floor and ceiling. If the floating price is between these contracted prices, no trade occurs. A commodity swap agreement is an agreement whereby a floating price based on the underlying commodity is traded for a fixed price over a specified period. Basis swaps provide a guaranteed price differential for natural gas from two different specified delivery points over a specified period. The fair value of open collar, commodity swap, and basis swap contracts reported in the consolidated balance sheets may differ from that which would be realized in the event the Company terminated its position in the respective contract.

Derivative Contracts

The following tables set forth the derivative gains (losses), net on the consolidated statements of operations:

	Year Ended December 31,		
(in thousands)	2023	2022	2021
Total gain (loss) on settled derivatives	$ 90,179	$(688,516)	$(268,686)
Total gain (loss) on unsettled derivatives	148,564	58,815	(115,161)
Total gain (loss) on derivatives, net	$238,743	$(629,701)	$(383,847)

Settled derivative gains (losses), net for the year ended December 31, 2023 includes gains of $46.7 million related to the termination of certain natural gas commodity derivative swap contracts prior to their contractual settlement dates. $39.1 million of such gains is attributable to early-terminated natural gas commodity derivative swap contracts covering production during the year ended December 31, 2023. Settled derivative gains (losses), net for the year ended December 31, 2022 includes losses of $158.4 million related to the termination of certain natural gas commodity derivative swap and collar contracts prior to their contractual settlement dates. $1.3 million of such losses is attributable to early-terminated natural gas

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commodity derivative swap contracts covering production during the year ended December 31, 2022. Settled derivative gains (losses), net for the year ended December 31, 2021 includes losses of $30.9 million related to the termination of certain natural gas commodity derivative swap and collar contracts prior to their contractual settlement dates. None of these losses is attributable to early-terminated natural gas commodity derivative swap contracts covering production during the year ended December 31, 2021.

As of December 31, 2023 and 2022, $0.3 million and $101.7 million, respectively, of settled derivatives were included in accounts payable and accrued liabilities on the Company's consolidated balance sheets. Of the $101.7 million, $57.0 million related to monetizations.

Volume of Derivative Activities

As of December 31, 2023, the Company's derivative activities based on volume and contract prices, categorized by primary underlying risk and related commodity, by year, were as follows:

The following table represents natural gas commodity derivatives indexed to NYMEX Henry Hub pricing:

Instrument	MMBtu	Weighted Average Price (USD)	Weighted Average Price Floor	Weighted Average Price Ceiling	Fair Value as of December 31, 2023 (in thousands)
2024					
Swap	99,662,500	$ 3.52			$ 82,071
2025					
Collars	49,275,000		$ 3.73	$ 4.13	$ 16,447

The following table represents natural gas basis derivatives based on the applicable basis reference price listed below:

Instrument	Basis Reference Price	MMBtu	Weighted Average Basis Differential	Fair Value as of December 31, 2023 (in thousands)
2024				
Swap	NGPL TXOK Basis	21,400,000	$ (0.54)	$ (5,059)
Swap	Transco Leidy Basis	32,940,000	$ (0.89)	$ (795)

The following table represents natural gas liquids commodity derivatives for contracts, by contract type, expiring throughout the years ending December 31, 2024 and 2025 based on the applicable index listed below:

Instrument	Commodity Reference Price	Gallons	Weighted Average Price (USD)	Fair Value as of December 31, 2023 (in thousands)
2024				
Swap	OPIS Purity Ethane Mont Belvieu	115,290,000	$ 0.25	$ 5,346
Swap	OPIS IsoButane Mont Belvieu Non-TET	7,686,000	$ 0.88	$ (468)
Swap	OPIS Normal Butane Mont Belvieu Non-TET	11,529,000	$ 0.87	$ (149)
Swap	OPIS Pentane Mont Belvieu Non-TET	19,215,000	$ 1.48	$ 1,163
Swap	OPIS Propane Mont Belvieu Non-TET	23,058,000	$ 0.77	$ 1,930

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Instrument	Commodity Reference Price	Gallons	Weighted Average Price (USD)	Fair Value as of December 31, 2023 (in thousands)
2025				
Swap	OPIS Purity Ethane Mont Belvieu	53,655,000	$0.27	$ 908
Swap	OPIS IsoButane Mont Belvieu Non-TET	3,832,500	$0.84	$ (74)
Swap	OPIS Normal Butane Mont Belvieu Non-TET	5,748,750	$0.82	$ (34)
Swap	OPIS Pentane Mont Belvieu Non-TET	7,665,000	$1.37	$ 203
Swap	OPIS Propane Mont Belvieu Non-TET	19,162,500	$0.73	$ 1,058

Subsequent Activity

On January 12, 2024, the Company terminated certain outstanding natural gas commodity derivative contracts indexed to NYMEX Henry Hub pricing and received a one-time cash settlement totaling $13.3 million. The following table represents a summary of such terminated contracts.

Instrument	MMBtu	Weighted Average Price (USD)	Weighted Average Price Floor	Weighted Average Price Ceiling	Settlement Value (in thousands)
2024					
Swap	12,000,000	$ 3.52			$ 8,350
2025					
Collars	34,770,000		$ 3.74	$ 4.14	$ 4,900

On January 29, 2024, the Company entered into an agreement to sell a call option and subsequently received a net premium of $23.5 million for contracts that settle in 2026 and 2027. The call option has an established ceiling price. If at the time of settlement the contracted settlement price exceeds the ceiling price, the Company pays the counterparty an amount equal to the difference between the contracted settlement price and the ceiling price multiplied by the contract volumes. Below is a summary of the call option position.

Instrument	Index	Daily Volume	Weighted Average Price Ceiling
2026			
Collars	NYMEX Henry Hub	100,000	$ 5.00
2027			
Collars	NYMEX Henry Hub	100,000	$ 5.00

Note 8 — Asset Retirement Obligations

The Company has recognized an estimated liability for its asset retirement obligations related to the future costs of plugging, abandonment, and remediation of natural gas producing properties. The present value of the estimated asset retirement obligations has been capitalized as part of the carrying amount of the related natural gas properties. As of December 31, 2023 and 2022, the liability has been accreted to its present value and during the years ended December 31, 2023, 2022, and 2021, accretion expense of $13.2 million, $12.8 million, and $10.0 million, respectively, was recognized and included in depreciation, amortization, depletion, and accretion in the consolidated statements of operations.

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The following table summarizes the activities of the Company's asset retirement obligations:

(in thousands)	2023	2022	2021
Balance, as of January 1,	$182,300	$158,968	$148,826
Additions through business combination	640	46,867	—
Liabilities incurred	89	303	923
Liabilities settled	(759)	(156)	(811)
Revision of estimates	—	(36,516)	—
Accretion of discount	13,206	12,834	10,030
Balance, as of December 31,	195,476	182,300	158,968
Less current portion	(2,271)	(1,165)	—
Asset retirement obligations, long-term	$193,205	$181,135	$158,968

Note 9 — Related Parties

During 2020, the Company entered into a note payable with its majority shareholder BNAC which allowed for a single drawdown in the amount of $10.0 million. On July 1, 2020, BKV Corp drew down $10.0 million with interest at 5.30%. During the year ended December 31, 2021, the Company recorded interest expense on this loan of $0.1 million in the consolidated statements of operations. The full balance of the loan was repaid during the year ended December 31, 2021.

On September 28, 2020, BKV Corp received $119.0 million in accordance with a separate loan agreement entered into with BNAC. Interest on the outstanding principal was 5.25% plus six-month LIBOR. During the year ended December 31, 2021, the Company paid down the outstanding balance of $19.0 million on this loan, and recorded interest expense of $0.2 million in the consolidated statements of operations.

On October 14, 2021, the Company entered into a loan agreement with its majority shareholder, BNAC and borrowed $116.0 million thereunder. Interest on the outstanding principal was SOFR plus an interest rate margin of 5.25% and payable on a semi-annual basis. On September 16, 2022, the Company repaid the $116.0 million principal, plus related interest, and terminated this loan agreement. During the years ended December 31, 2022 and 2021, the Company recognized interest expense of $5.5 million and $1.4 million, respectively.

On November 8, 2021, the Company entered into a loan agreement with BNAC and borrowed $50.0 million thereunder. Interest on the outstanding principal was LIBOR plus an interest rate margin of 5.25%. On June 1, 2022, the Company repaid the principal plus related interest, and terminated this loan agreement. During the years ended December 31, 2022 and 2021, the Company recognized interest expense of $0.9 million and $0.4 million, respectively.

On December 23, 2021, the Company entered into a loan agreement with Temple Generation I LLC (the "Power Plant"), a wholly owned subsidiary of BKV-BPP Power, LLC (see *Note 14 — Equity Method Investment* for further discussion on BKV-BPP Power, LLC). This loan agreement was subsequently amended on December 1, 2022 to allow the Power Plant to borrow up to $10.0 million from the Company ("Power Plant Loan"). Interest on the outstanding principal is at six-month SOFR plus an interest rate margin of 4.75%. On June 13, 2023 and June 20, 2023, BKV-BPP Power, LLC drew down $3.0 million and $5.0 million, respectively. On July 10, 2023, BKV-BPP Power, LLC repaid the $8.0 million, including accrued interest. During the year ended December 31, 2023, the Company recognized interest income on the Power Plant Loan of an immaterial amount, and during the years ended December 31, 2022 and 2021, recognized zero interest income on the Power Plant Loan. The Power Plant Loan expired on November 30, 2023 and was not renewed.

On March 10, 2022, the Company entered into a loan agreement (the "$75 Million Loan Agreement") with BNAC and borrowed $75.0 million thereunder. On June 15, 2022, the Company entered into a subordination agreement with BNAC whereby the $75.0 million is subordinate to the term loans under the Company's Term Loan Credit Agreement, further discussed in *Note 4 — Debt*. Interest on the outstanding principal is SOFR plus an interest rate margin of 5.25%, and as of December 31, 2023, the interest rate was 10.41%. The principal balance of $75.0 million is due on December 31, 2027, including any unpaid interest. Financial covenants under the $75 Million Loan Agreement are consistent with those of the Term Loan Credit Agreement as discussed in *Note 4 — Debt.* As of December 31, 2023 and 2022, interest payable under the $75 Million Loan Agreement was $11.4 million and $4.3 million, respectively. For the years ended December 31, 2023 and 2022, interest expense recognized on the $75 Million Loan Agreement was $7.1 million and $ 4.3 million, respectively.

As of December 31, 2023 and 2022, the Company had payables of $0.9 million and $5.2 million, respectively, to BNAC for current tax expense included in income taxes payable to related party on the consolidated balance sheets. During these periods, these amounts due to BNAC are related to reimbursements for income tax related items. Separately, as of December 31, 2023 and 2022, the Company had a receivable from BNAC of $0.1 million and $0.2 million, respectively, related to shared general and administrative expenses.

As of December 31, 2023 and 2022, the Company had accounts receivable from BKV-BPP Power, LLC of $0.4 million and $0.2 million, respectively. These receivable balances are related to reimbursement for certain expenses paid on behalf of BKV-BPP Power, LLC and amounts receivable under an Administration Services Agreement ("ASA") between the Company and BKV-BPP Power, LLC. See *Note 14 — Equity Method Investment* for further discussion of the ASA and the Company's equity method investments. During the years ended December 31, 2023, 2022, and 2021, the Company recognized $3.6 million, $2.7 million and $0.2 million, respectively, of income related to the services provided under the ASA, which is included in related party and other on the consolidated statements of operations.

On February 17, 2023, the Company issued a letter of credit from the SCB Credit Facility on behalf of BKV-BPP Retail LLC in the amount of $3.5 million. See *Note 4 — Debt* for further information on this credit facility. BKV-BPP Retail, LLC is a wholly owned subsidiary of BKV-BPP Power, LLC, and related party to the Company.

The Company's ultimate parent company, Banpu Public Company Limited, is also the ultimate parent of Banpu Power US Corporation ("BPP US"), the Company's partner in a joint venture which is discussed further in *Note 14 — Equity Method Investment*. As of December 31, 2023, the Company did not have any accounts receivable from BPP US and as of December 31, 2022, the accounts receivable from BPP US was a negligible amount.

Note 10 — Revenue from Contracts with Customers

All of the Company's revenues are generated in the states of Pennsylvania and Texas. Revenues consist of the following:

	Year Ended December 31, 2023		
(in thousands)	**Pennsylvania**	**Texas**	**Total**
Natural gas	$ 57,678	$452,168	$509,846
NGLs	—	187,860	187,860
Oil	—	8,445	8,445
Total natural gas, NGL, and oil sales	$ 57,678	$648,473	$706,151
Marketing revenues	—	8,710	8,710
Midstream revenues	4,635	11,533	16,168
Related party and other	—	8,251	8,251
Total	$ 62,313	$676,967	$739,280

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	Year Ended December 31, 2022		
(in thousands)	**Pennsylvania**	**Texas**	**Total**
Natural gas	$ 246,200	$1,064,139	$1,310,339
NGLs	—	311,542	311,542
Oil	—	11,866	11,866
Total natural gas, NGL, and oil sales	$ 246,200	$1,387,547	$1,633,747
Marketing revenues	—	11,001	11,001
Midstream revenues	5,845	6,831	12,676
Related party and other	—	2,799	2,799
Total	$ 252,045	$1,408,178	$1,660,223

	Year Ended December 31, 2021		
(in thousands)	**Pennsylvania**	**Texas**	**Total**
Natural gas	$ 131,207	$465,843	$597,050
NGLs	—	225,135	225,135
Oil	—	7,560	7,560
Total natural gas, NGL, and oil sales	$ 131,207	$698,538	$829,745
Marketing revenues	—	52,616	52,616
Midstream revenues	6,917	—	6,917
Related party and other	—	251	251
Total	$ 138,124	$751,405	$889,529

As of December 31, 2023 and 2022, the Company's receivables from contracts with customers were $32.8 million and $114.7 million, respectively.

Note 11 — Accounts Payable and Accrued Liabilities

Accounts payable and accrued liabilities included in current liabilities consists of the following:

	December 31,	
(in thousands)	**2023**	**2022**
Accounts payable	$ 47,504	$ 74,957
Commodity derivative settlements payable	347	44,754
Commodity derivative monetizations payable	—	56,972
Oil and gas production and other taxes payable	48,857	37,530
Revenues payable	21,765	28,976
Other accrued liabilities	30,700	29,286
Total	$149,173	$272,475

Note 12 — Equity-Based Compensation

On January 1, 2021, the BKV Corporation 2021 Long-Term Incentive Plan (the "Plan") was established (the "Initial Incentive Award Date") by the adoption of the Plan by the Board of Directors, which allows for the grant of incentive awards to employees and non-employee Directors of the Company in the form of RSUs. Each RSU represents the contingent right to receive one share of common stock of the Company. As of December 31, 2023, the maximum number of RSUs authorized to be awarded under the Plan was 7,470,588. However, of the total authorized RSUs under the Plan, only 60% may be awarded on or before

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December 31, 2022 without the written approval of the Board of Directors of the Company. Thereafter, no more than 80% of the total RSUs may be awarded without the written approval of the Board of Directors of the Company. For accounting purposes, management evaluated grants of incentive awards from the Plan in accordance with the FASB's Accounting Standards Codification ("ASC") 718 — *Compensation-Stock Compensation* ("ASC 718") and determined a grant date for all annual incentive awards, including those anticipated to be legally granted in the three years subsequent to the Initial Incentive Award Date because all grant date criteria had been satisfied and compensation expense and forfeitures were accounted for accordingly. Under ASC 718, as of December 31, 2023, 7,724,499 were considered to have been granted under the Plan since the Plan's inception when taking into consideration performance RSUs at the maximum performance level and time-based RSUs anticipated to be legally granted in the three years following the Initial Incentive Award Date. As of December 31, 2023, of the awards considered granted under ASC 718, since the Initial Incentive Award Date of the Plan, 790,743 RSUs were not considered legally granted.

RSUs are granted in the form of PRSUs and time-based restricted stock units ("TRSUs"). The shares of common stock issued in settlement of the RSUs include a put right (the "Plan Put Right") available to the incentive award grant recipients (the "Participants"). If a Participant's employment is terminated due to voluntary resignation, and certain other conditions are met, a Participant is able to elect the Company to purchase the shares issued in settlement of his or her RSUs at fair market value of the Company's common stock at the time the election is made by the Participant. The Plan Put Right is only available to Participants upon the occurrence of certain events as defined in the Plan. As discussed below in *Modification of Terms*, this Plan Put Right was modified on November 5, 2021 to add a 181 day holding period following vesting of the RSUs. In addition, the Company has a purchase right (the "Call Right") which allows for the purchase of shares of common stock issued in the settlement of the RSUs from terminated Participants at fair market value on the date of the purchase, at the Company's discretion. These features, specifically the Plan Put Right, required the Company to treat the incentive awards as cash-settled or liability classified in the consolidated balance sheets of the Company until the Plan was modified as described below.

Under liability treatment, during the year ended December 31, 2021, the Company incurred $26.7 million of equity-based compensation expense, which is included within the consolidated statements of operations as general and administrative expense. Valuation methodologies used were consistent with those described below.

Modification of Terms

On November 5, 2021, the Board of Directors of the Company approved the First Amendment to the BKV Corporation 2021 Long-Term Incentive Plan (the "Plan Amendment"). The Plan Amendment included a provision to require all Participants of the Plan to hold vested shares of common stock issued in settlement of RSUs for a minimum of 181 days (the "Holding Period") prior to having the ability to exercise the Plan Put Right. The Plan Amendment also applied the Holding Period to the Call Right. Upon modification, the RSUs under the Plan are considered to be settled in equity, as the Holding Period is a reasonable period of time to experience the risk and rewards of an equity instrument. However, due to the existence of the Plan Put Right, the Company recognized the incentive awards within mezzanine equity on the consolidated balance sheets as of the date of Plan Amendment. The fair market value of the RSUs prior to the modification was $25.3 million. On the date of the Plan Amendment, this amount was transferred from liabilities into mezzanine equity on the consolidated balance sheets of the Company. All Participants of the plan agreed to the terms of the Plan Amendment. See *Note 13 — Stockholders' Equity and Mezzanine Equity* for additional discussion of the Company's treatment of equity-based compensation within mezzanine equity.

The Plan Amendment also established the Sell Fund Repurchase Program (the "Sell Fund"). Under the Sell Fund, Participants are able to tender for repurchase their vested shares of common stock to the Company after the required Holding Period, to the extent expressly permitted under their respective award agreements. On December 21, 2021, the Board of Directors of the Company approved the opening of the Company's first Sell Fund window, which closed on December 29, 2021. The opening of the Sell Fund

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window set forth requirements, which limited participants in the number of shares that can be tendered and a limitation whereby, in aggregate, the total value of shares tendered by all Participants cannot exceed $2.0 million per year. Sell Fund windows could be opened twice per year, and the Sell Fund remained in effect until December 31, 2023. During the year ended December 31, 2021, the Company repurchased 4,974 shares at $22.12 per share for a total of $0.1 million. There were no Sell Fund windows opened during the years ended December 31, 2023 or 2022.

Performance-Based Restricted Stock Units

During the year ended December 31, 2023, the Company did not grant any PRSUs under the Plan. Since inception of the Plan, the PRSUs granted took into consideration performance units at the maximum performance levels, or 200%. PRSUs cliff vest and were subject to a vesting or performance period beginning January 1, 2021 and ending on December 31, 2023 (the "Performance Period"). The table below summarizes the PRSU activity for the year ended December 31, 2023, taking into consideration vesting and forfeitures at actual performance levels during this period:

(in thousands, except per share amounts)	Shares	Weighted-Average Grant Date Fair Value
Unvested PRSUs as of January 1, 2023	5,910	$ 22.20
Adjustment[(1)]	(1,673)	$ 19.02
Forfeited	(270)	$ 21.80
Unvested PRSUs as of December 31, 2023	3,967	$ 19.02

(1) The PRSUs were adjusted to reflect the actual performance level at the time the PRSUs vested compared to the PRSUs granted and forfeited since inception, which took into consideration the maximum performance levels, or 200%.

PRSUs were eligible to be earned based on three performance conditions: (i) Annualized Total Shareholder Return ("TSR") of fully diluted common stock during the performance period weighted at 60%, (ii) Return on Capital Employed ("ROCE") based on the average annual performance over the Performance Period weighted at 20%, and (iii) IPO readiness which is based on the Company's capability to be listed on a public stock exchange at certain points during the Performance Period weighted at 20%. As of December 31, 2023, or the Performance Period, the Company achieved its goals as follows: TSR met its threshold at 136%, ROCE met its threshold at 131%, and IPO readiness met its threshold at 200%. In February 2024, the Plan's committee approved the Company's goals and the PRSUs outstanding as of December 31, 2023 vested.

The TSR component of the awards is a market-based condition. To calculate the grant date fair value of the TSR component of the vested awards, the Company utilized the Monte Carlo Simulation pricing model, which calculated multiple potential outcomes to establish the grant date fair value based on the most likely outcome. The weighted average grant date fair value of the TSR component of the PRSU awards vested during the year ended December 31, 2023 was $16.38.

ROCE and IPO readiness are considered to be non-market performance conditions. The grant date fair value of the PRSUs vested during the year ended December 31, 2023 took into account the grant date fair value for ROCE and IPO readiness, due to the non-market performance conditions being probable of achievement as of the respective modification date or grant date which establishes a grant date fair value. The weighted average grant date fair value of the ROCE and IPO readiness components of PRSU awards vested during the year ended December 31, 2023 was $22.26.

After the modification of terms, during the year ended December 31, 2021, equity-based compensation expense related to the PRSUs was $3.1 million. During the years ended December 31, 2023 and 2022, equity-based compensation expense was $22.2 million and $27.3 million, respectively. These costs are included in general and administrative expenses in the consolidated statements of operations.

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Time-Based Restricted Stock Units

During the year ended December 31, 2023, the Company did not grant any TRSUs under the Plan. As of December 31, 2023, of the awards considered granted under ASC 718 since the inception of the Plan, 790,743 TRSUs were not considered legally granted. Under the applicable provisions of the Plan, the TRSU incentive award was anticipated to be granted in the form of four annual awards. One quarter of the annual award requires no service for vesting and vests immediately upon the grant date. The remaining three quarters of the annual award vest in equal portions upon the subsequent three anniversary dates following the grant date. The remaining annual awards are anticipated to be granted on the first, second, and third anniversaries of the initial TRSU award date, subject to continued employment with the Company and Board of Director approval. Vesting for these anticipated three annual awards is expected to follow the same vesting schedule as the first annual awards based on the legal grant date. Upon an IPO of the Company, all unvested and legally granted and outstanding awards under the Plan will vest immediately. Awards accounted for as granted under ASC 718, but not legally granted at such time, will not vest and will be treated accordingly.

The following table summarizes the TRSU activity for the year ended December 31, 2023:

(in thousands, except per share amounts)	Shares	Weighted-Average Grant Date Fair Value
Unvested TRSUs as of January 1, 2023	1,034	$ 22.32
Vested[(1)]	(235)	$ 22.24
Forfeited	(72)	$ 22.12
Unvested TRSUs as of December 31, 2023	727	$ 22.37

(1) For the year ended December 31, 2023, the total fair value of the shares vested was $26.30.

As of December 31, 2023, there was $13.3 million of unrecognized compensation expense related to the TRSU awards, which will be amortized over a weighted average period of 3.7 years.

After the modification of terms, during the year ended December 31, 2021, equity-based compensation expense related to the TRSUs was $0.5 million. During the years ended December 31, 2023 and 2022 equity-based compensation expense was $3.6 million and $4.6 million, respectively. These costs are included in general and administrative expenses in the consolidated statements of operations.

Tax Impact

For the years ended December 31, 2023, 2022, and 2021, the Company recognized $4.2 million, $6.4 million and $6.6 million, respectively, of tax benefit related to equity-based compensation.

Note 13 — Stockholders' Equity and Mezzanine Equity

Reverse Stock Split

On October 30, 2023, the Company completed a one-for-two reverse stock split. As a result of the reverse stock split, every two shares of outstanding common stock were combined and now represent one share of common stock and fractional shares were paid out in cash to the common stockholders, which amounted to an immaterial amount. No fractional shares were issued in connection with the reverse stock split.

Following the reverse stock split, the Company's authorized capital stock consists of 300,000,000 shares of common stock, $0.01 par value per share, of which 66,275,866 shares are issued and outstanding, and 80,000,000 shares of preferred stock, $0.01 par value per share, of which no shares are issued and

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outstanding. All shares of common stock issuable upon exercise of equity awards, as well as the applicable exercisable prices and weighted average fair value of such equity awards, and per share amounts contained throughout these consolidated financial statements have been retroactively adjusted for all past and current periods presented. On an as-adjusted basis to give effect to the reverse stock split, the number of shares of common stock issued and outstanding as of December 31, 2023 and 2022 was 66,275,866 and 58,662,898, respectively.

Common Shares Issued and Outstanding

As of December 31, 2023 and 2022, the Company had 66,275,866 and 58,662,898, respectively, of common shares issued and outstanding. See discussion below in the *Treasury Stock* section of this note for discussion of redemptions and purchases of the Company's own common stock during the years ended December 31, 2023 and 2022.

During the year ended December 31, 2021, the Company declared, and paid to the common stockholders, a cash dividend of $1.50 per share of common stock outstanding for a total of $88.1 million. There were no cash dividends declared or paid during the years ended December 31, 2023 and 2022.

Minority Ownership Puttable Shares — Mezzanine Equity

Of the 47,350,000 shares issued on May 1, 2020, 1,114,385 shares were issued to certain non-controlling management shareholders of BKV as a part of a series of acquisitions, including the corporate restructuring of BKV Corp, and 1,000,000 shares were issued as part of the merger with Kalnin Ventures LLC (collectively, the "Management Shares"). As of December 31, 2023 and 2022, there were 1,976,689 of these minority shares outstanding. The Management Shares include a put and call feature which requires BKV to repurchase shares from these shareholders upon the occurrence of certain events stipulated in the Stockholders' Agreement at either $20.00 per share or the fair market value per share, depending on the type and timing of the triggering event. In addition, BKV may call and repurchase the Management Shares upon the occurrence of certain events stipulated in the Stockholders' Agreement at either $20.00 per share or the fair market value per share, depending on the type and timing of the triggering event. The Stockholders' Agreement, and these put and call features, will terminate upon completion of an IPO by the Company. Since the shares are not mandatorily redeemable, but can become redeemable at the option of the holder, the fair market value of the Management Shares upon issuance was recognized within mezzanine equity. As of December 31, 2023 and 2022, management has determined it is probable that the shares will become redeemable at the end of the three-year period and has elected to carry the shares at redemption value, or fair market value, in mezzanine equity on the consolidated balance sheets. During the years ended December 31, 2023, 2022, and 2021, the Company recognized adjustments of $2.5 million, $11.9 million, and $6.9 million, respectively, to the carrying value of the Management Shares to adjust to redemption value.

During the year ended December 31, 2021, certain shares were redeemed (see*Treasury Stock* section for share counts and redemption prices) causing the specific redeemed shares to no longer retain the previously mentioned rights. Accordingly, upon redemption the redeemed shares and associated carrying values were reclassified to permanent equity. No Management Shares were redeemed during the years ended December 31, 2023 and 2022.

Employee Stock Purchase Plan — Mezzanine Equity

The Company's Employee Stock Purchase Plan (the "ESPP") was adopted on November 1, 2021 and reserves 3,735,294 shares of common stock for purchase by eligible employees of the Company. The number of shares available is subject to adjustment based on anti-dilution provisions in the Stockholders' Agreement. The ESPP allows for certain eligible non-employees and members of the Board of Directors to purchase shares under the ESPP in addition to eligible employees of the Company. During the years ended December 31, 2022 and 2021, the Company issued 2,563 and 143,605 shares of common stock, respectively, under the ESPP. There were no shares issued under the ESPP during the year ended December 31,

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2023. The shares sold under the ESPP include a put right which allows for holders of the ESPP shares to require the Company to the purchase the shares upon the occurrence of certain events stipulated by the ESPP. The shares can also be purchased by the Company, at its discretion upon the occurrence of certain events, as stipulated in the ESPP. Because the shares are not mandatorily redeemable but can become redeemable at the option of the eligible employee, non-employee, or Directors, the fair market value of the shares of common stock sold under the ESPP is recognized within mezzanine equity upon issuance. Management has determined it is probable that the shares will become redeemable and has elected to carry the shares at redemption value, or fair value, in mezzanine equity on the consolidated balance sheets. During the years ended December 31, 2023, 2022, and 2021, the Company recognized an adjustment of $0.2 million, $0.9 million, and $0.1 million, respectively, to the carrying value of the ESPP shares.

Equity-Based Compensation — Mezzanine Equity

As discussed in *Note 12 — Equity-Based Compensation,* the Plan includes the Plan Put Right. Accordingly, management has determined it is probable the shares issued in settlement of the RSUs upon vesting will become redeemable and has elected to carry the shares at redemption value which equals fair market value. During the years ended December 31, 2023, 2022, and 2021, the Company recognized an adjustment to the pro-rata portion of the RSUs which have vested in the amounts of $15.6 million, $24.4 million, and $5.0 million, respectively. The maturities related to the redemption feature are in accordance with the vesting terms discussed in *Note 12 — Equity-Based Compensation*, taking into account the three year and 181 day holding periods. During the years ended December 31, 2023, 2022, and 2021, the Company issued 133,622, 109,339, and 58,173, respectively, shares of common stock in settlement of vested incentive awards. As of December 31, 2023 and 2022, the Company has 301,134 and 167,512, respectively, shares of common stock issued in settlement of vested incentive awards outstanding, which are included in equity-based compensation within mezzanine equity on the consolidated balance sheets of the Company at redemption value of $7.9 million and $4.9 million, respectively.

Preferred Shares — Mezzanine Equity

On December 15, 2020, the Company authorized 80,000,000 shares of preferred stock at $10.00 par value. Of the shares of preferred stock authorized, 9,900,000 shares were designated as par Series A Cumulative Redeemable Preferred Stock (“Series A”) and these designated shares were issued during 2020 in a private exchange for $99.0 million. Cost associated with the issuance was $4.1 million. In conjunction with the issuance of the Series A shares, 100,000 shares of common stock were issued.

Series A shares carry quarterly cumulative dividends at a rate of 10% per annum for the first five years, 18% per annum for years 6 through 10, and 20% per annum, thereafter. The holder may only redeem the Series A shares upon the occurrence of liquidation, winding-up, dissolution, or change in control of the Company. The Company may also redeem the Series A shares, in whole or in part, at any time. Upon redemption by either party, the redemption value is at a price equal to $12.25 per share plus unpaid accumulated dividends at the time of redemption. Holders of the preferred shares do not have voting rights with respect to their preferred shares, however they are allowed certain consensual rights. The Series A shares include conversion features allowing for conversion into 7,425,000 shares of a new series of preferred stock and 34,873,941 shares of common stock. However, the shares do not become convertible until 10 years from the date of issuance. The number of conversion shares are adjusted pro-rata for any redemptions prior to conversion. Since the Series A shares can become redeemable at the option of the holder, but are not mandatorily redeemable, the Series A shares are classified as mezzanine equity. Management has determined it is probable the Company will exercise its redemption rights prior to the increase in cumulative dividends after year five; therefore, the carrying value of the shares is being accreted to redemption value over the expected five year period. For the year ended December 31, 2021, the Company recognized $3.7 million in accretion of preferred stock to redemption value within mezzanine equity on the consolidated balance sheets.

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During April 2021, the Board of Directors of the Company declared a dividend payable to common stockholders which in turn required payment of the cumulative dividends on the Series A shares. During May 2021, the Company paid $10.3 million in dividends to preferred stock shareholders. The dividend payment represented cumulative dividends for the period of December 15 through December 31, 2020, and the year ended December 31, 2021. In conjunction with the dividend, as required by the Series A shareholders' agreement, the Company redeemed 501,000 shares of outstanding preferred stock for $6.1 million, of which $1.3 million represented a deemed dividend to Series A shareholders for required premiums paid upon redemption. The deemed dividend represents the difference between the redemption amount paid by the Company and the carrying value of the preferred stock prior to redemption and is reflected as such within the consolidated statements of stockholders' equity and mezzanine equity for the year ended December 31, 2021.

On October 8, 2021, the Company notified the holders of the remaining outstanding shares of preferred stock that their shares would be redeemed on October 18, 2021. The Company paid $115.1 million in order to redeem the remaining outstanding shares for preferred stock, of which $22.6 million represented a deemed dividend to preferred shareholders for required premiums paid upon redemption. The deemed dividend represents the difference between the redemption amount paid by the Company and the carrying value of the preferred stock prior to redemption and is reflected as such within the consolidated statements of stockholders' equity and mezzanine equity for the year ended December 31, 2021. As of December 31, 2023 and 2022, there were no outstanding shares of preferred stock.

Treasury Stock

On October 18, 2021 the Company purchased 50,000 shares of its common stock in conjunction with the redemption of the remaining outstanding shares of Series A shares on the same date. The shares were repurchased for $1.1 million at a price of $22.12 per share.

As discussed in *Note 12 — Equity-Based Compensation*, on December 31, 2021, the Company purchased 4,974 shares of its common stock for $0.1 million at a price of $22.12 per share.

During February, April, and December of 2021, the Company purchased a total of 137,696 shares of common stock from non-controlling management shareholders for $2.8 million at a price of $20.00 per share.

During the year ended December 31, 2022, the Company purchased 110 shares of its common stock for an immaterial amount at a price of $33.58 per share.

Note 14 — Equity Method Investment

On July 30, 2021, the Company completed the formation of a 50/50 joint venture named BKV-BPP Power, LLC (the "Joint Venture") with BPP US. The Joint Venture was formed for the sole purpose of purchasing and operating a power plant and other related activity. During August 2021, the Company contributed $43.0 million to the Joint Venture in the form of a deposit for the purchase of the Power Plant. On November 1, 2021 the Joint Venture completed the purchase of the Power Plant for $440.9 million. To complete the purchase on November 1, 2021, the Company contributed an additional $44.0 million, and BPP US contributed an equal additional $87.0 million.

In addition to the contributions from the members of the Joint Venture, $141.0 million was provided from BPP US in the form of a term loan, and $141.0 million was provided by the Company's majority shareholder BNAC, also in the form of a term loan. Of the total $282.0 million term loans provided by affiliates, $15.0 million was for the purposes of working capital. Both term loans mature on November 1, 2026.

In December 2021, the Company entered into the ASA with the Joint Venture, in which the Company provides certain services as required by the ASA, on an annual basis with options to extend. During the years

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ended December 31, 2023, 2022, and 2021, the Company recognized revenues of $3.6 million, $2.7 million, and $0.2 million, respectively, related to the services provided under the ASA, which is included in related party and other on the consolidated statements of operations.

On July 10, 2023, the Joint Venture acquired CXA Temple 2, LLC, the owner of 100% of the interests in Temple II, a combined cycle gas turbine and steam turbine power plant located on the same site as Temple I in the Electric Reliability Council of Texas North Zone in Temple, Texas for an aggregate purchase price of $460.0 million. Temple I and Temple II deliver power to customers on the ERCOT power network in Texas.

The Joint Venture is independently operated and jointly owned by BKV Corp and BPP US through a Board of Directors consisting of eight members, four of which are appointed by BKV Corp. The remaining four members of the Board of Directors of the Joint Venture are appointed by BPP US. The Joint Venture was determined to be a variable interest entity due to its need for additional funding from its members. BKV Corp is not the primary beneficiary of the Joint Venture; while the majority of the ability to influence the significant activities of the Joint Venture is controlled by the JV Board, certain rights to influence the significant activities of the Joint Venture have been retained solely by BPP US, as defined by the Joint Venture's LLC agreement. Accordingly, the equity method of accounting is used by BKV Corp to account for its interest in the Joint Venture. BKV Corp's initial investment, including direct transaction costs, was $88.5 million, which represents the Company's maximum exposure to loss from the investment.

During the years ended December 31, 2023, 2022, and 2021, the Company recognized, based on its 50% ownership interest in the Joint Venture, earnings of $16.9 million, $8.5 million, and $0.9 million, respectively.

On September 27, 2023, the JV Board authorized a dividend to the Company of $10.0 million, which was then paid on October 17, 2023.

The table below sets forth a reconciliation of BKV Corp's investment in the Joint Venture:

Reconciliation of Equity Method Investment (in thousands)	
Balance as of December 31, 2021	$ 89,320
Equity in earnings of Joint Venture	8,493
Direct transaction costs	72
Balance as of December 31, 2022	97,885
Equity in earnings of Joint Venture	16,865
Dividends from Joint Venture	(10,000)
Balance as of December 31, 2023	$104,750

The tables below set forth the summarized financial information of the Joint Venture based on audited numbers:

Balance Sheet (in thousands)	**As of December 31, 2023[(1)]**	**2022[(2)]**
Current assets	$ 142,672	$ 45,341
Noncurrent assets	880,097	434,455
Total assets	$1,022,769	$479,796
Current liabilities	$ 122,334	$287,432
Noncurrent liabilities	694,203	—
Total liabilities	816,537	287,432
Members' equity	206,232	192,364
Total liabilities and members' equity	$1,022,769	$479,796

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(1) Amounts are based on the Joint Venture's audited financial statements.

(2) Amounts are based on the Joint Venture's audited financial statements, which differ from the Company's 2022 audited financial statements. This is due to the timing of the Company's financial statements being issued prior to the Joint Venture's audit.

Income Statement (in thousands)	Year Ended December 31,		
	2023[1]	2022[2]	2021[2]
Total revenues, net	$326,604	$294,736	$23,918
Operating expenses	243,075	255,230	23,140
Income from operations	83,529	39,506	778
Interest expense	(50,524)	(19,662)	(2,599)
Other income	863	377	—
Net income (loss)	$ 33,868	$ 20,221	$ (1,821)

(1) Amounts are based on the Joint Venture's audited financial statements.

(2) Amounts are based on the Joint Venture's audited financial statements, which differ from the Company's 2022 audited financial statements. These differences and their impacts on the Company's earnings in equity affiliate were trued-up and recognized in the following period.

Note 15 — Credit and Other Risk

Each of the derivative contracts entered into by the Company with counterparties is subject to the terms of an International Swap Dealers Association master agreement ("Master Agreement"). On August 4, 2022, the Company entered into a third amendment to a Master Agreement with a certain counterparty (the "Counterparty"), which includes a cross default provision pursuant to which a default by the Company related to the covenants under the Company's Term Loan Credit Agreement, see *Note 4 — Debt*, would cause a default under the Master Agreement. Under the third amendment, the Company also agreed to terminate or novate, at its election, at least $100.0 million of its derivative contracts. On September 9, 2022, the Company terminated derivative contracts for $100.2 million with the Counterparty to satisfy this requirement. In connection with such termination, the Company made cash payments to the Counterparty of $100.2 million, all of which was paid by the end of 2022. The fair market value of derivative contracts as of December 31, 2022 under the Counterparty's Master Agreement was $35.3 million, which was included in current commodity derivative liabilities on the Company's consolidated balance sheets.

The Company is not currently aware of any exceptional event, dispute, risks, or contingent liabilities that could have a material impact on the assets and liabilities, results, financial position, or operations of the Company.

The Company is subject to U.S. federal income tax as well as income in various state jurisdictions, and the Company's operating cash flow is sensitive to the amount of income taxes the Company must pay. In the jurisdictions in which the Company operates or previously operated, income taxes are assessed on earnings after consideration of all allowable deductions and credits. Changes in the types of earnings that are subject to income tax, the types of costs that are considered allowable deductions (such as intangible drilling costs) and the timing of such deductions, or the rates assessed on the Company's taxable earnings would all impact the Company's income taxes and resulting operating cash flow. In addition, new taxes are, from time to time, proposed and if enacted, could adversely impact the Company's financial condition and results of operations.

Substantially all of the Company's accounts receivable result from the sale of natural gas and joint interest billings. The Company sells natural gas, NGLs, and oil to fewer than five customers and

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bills working interest owners for costs related to development of the Company's natural gas properties. As of December 31, 2023 and 2022, one purchaser accounted for more than 10% of accounts receivables, and for the years ended December 31, 2023, 2022, and 2021, the same purchaser's revenues were $476.5 million, $1.1 billion, and $550.9 million, respectively, of the Company's revenues. Another purchaser's revenues, that also accounted for more than 10% of the Company's revenues during the years ended December 31, 2023, 2022, and 2021,amounted to $170.6 million, $282.3 million, and $199.5 million, respectively. The Company does not believe that the loss of these customers would have a material adverse effect on the consolidated financial statements because alternative customers are readily available.

Note 16 — Commitments and Contingencies

From time to time, the Company may be subject to various claims, title matters, and legal proceedings arising in the ordinary course of business, including environmental contamination claims, personal injury and property damage claims, claims related to joint interest billings and other matters under natural gas operating agreements, and other contractual disputes. The Company maintains general liability and other insurance to cover some of these potential liabilities. All known liabilities are fully accrued based on the Company's best estimate of the potential loss. While the outcome and impact on the Company cannot be predicted with certainty, for the periods presented in the consolidated financial statements, the Company believes that its ultimate liability, with respect to any such matters, will not have a significant impact or material adverse effect on its financial positions, results of operations, or cash flows. Results of operations and cash flows, however, could be significantly impacted in the reporting periods in which such matters are resolved.

The Company was involved in an arbitration against an operator related to the breach of various provisions of a certain agreement related to the construction and operation of a midstream gathering system. On February 18, 2022, the Company agreed to settle with the operator, and as a result, received payment of $35.0 million to settle all past disputes and agreed to a midstream gathering rate going forward. Of the $35.0 million, $18.1 million was considered collection of accounts receivable, and the remaining $16.9 million was recognized as a gain on settlement of litigation in the consolidated statements of operations for the year ended December 31, 2022.

The Company has volume commitments in the form of gathering, processing, and transportation agreements with various third parties that require delivery of 769,250,996 dekatherms of natural gas. The majority of the agreements terminate by 2029, with one agreement extending through 2036. As of December 31, 2023, the aggregate undiscounted future payments required under these contracts total $208.9 million. The Company expects to fulfill the commitments from existing productive wells.

The Company may potentially be responsible for remitting lease related payments to certain leaseholders and has recorded a liability of approximately $5.7 million. Of the $5.7 million, $0.4 million was incurred during the year ended December 31, 2021. The Company will continue to evaluate these estimates and revise any recorded obligations and contingencies as necessary. During the years ended December 31, 2023 and 2022, there were no changes to the estimated value of $5.7 million of liabilities previously reported in the consolidated balance sheet.

As a part of the consideration paid for the Devon Barnett Acquisition, additional cash consideration will be required to be paid by the Company if certain thresholds are met for average Henry Hub natural gas and WTI crude oil prices for each of the calendar years during the period beginning January 2021 through December 31, 2024 (the "Devon Barnett Earnout"). Average Henry Hub payouts and threshold are as follows: $2.75/MMBtu $20.0 million, $3.00/MMBtu $25.0 million, $3.25/MMBtu $35.0 million, and $3.50/MMBtu $45.0 million; average WTI payouts and thresholds are as follows for these periods: $50.00/Bbl $10.0 million, $55.00/Bbl $12.5 million, $60.00/Bbl $15.0 million, and $65.00/Bbl $20.0 million. The maximum remaining amount payable under the arrangement is $130.0 million, or $65.0 million per year for the years ending December 31, 2023 through 2024. Payments are due in the month following the end of the respective measurement period for which the hurdle rates are set. During the year ended December 31, 2023, the

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Company paid the 2022 portion of the arrangement of $65.0 million on January 13, 2023. As of December 31, 2023, the 2023 portion of the arrangement is considered to be settled resulting in a settlement of $20.0 million, which is reflected as contingent consideration payable within current liabilities on the consolidated balance sheets, and was paid on January 12, 2024. As described in *Note 6 — Fair Value Measurements*, management uses NYMEX forward pricing estimates for both Henry Hub and WTI hurdle rates and Monte Carlo simulations to determine the fair value of the contingent consideration. As of December 31, 2023 and 2022, the Company's estimate of the fair value of the unsettled contingent consideration was $47.5 million and $72.5 million, respectively. The change in the fair value of the contingent consideration, considering the settlements of $20.0 million and $65.0 million for years ended December 31, 2023 and 2022 was a gain of $25.0 million and a gain of $5.0 million, respectively. For the year ended December 31, 2021, the change in the fair value of the contingent consideration was a loss of $194.9 million. These changes in the fair value during these periods impacted the associated liability on the consolidated balance sheets and recognition of the gain or loss was recognized in the gains (losses) on contingent consideration liabilities on the consolidated statements of operations.

In conjunction with the Exxon Barnett Acquisition (see *Note 3 — Acquisition*), additional cash consideration will be required to be paid by the Company if certain thresholds for future Henry Hub natural gas prices are met for the years ended December 31, 2023 and 2024. Payouts and thresholds were as follows for the year ended December 31, 2023: $4.00/MMBtu $10.0 million, $4.50/MMBtu $17.5 million, and $5.00/MMBtu $25.0 million, which resulted in a zero payment on the 2023 portion of the arrangement. Payouts and thresholds are as follows for the year ended December 31, 2024: $3.75/MMBtu $10.0 million, $4.25/MMBtu $17.5 million, and $4.75/MMBtu $25.0 million. Payments of the additional cash consideration are due by January 31 of the calendar year following the applicable threshold measurement periods. The fair value of the contingent consideration as of December 31, 2023 and 2022 was $2.2 million and $15.6 million, respectively. The change in the fair value of the contingent consideration for the years ended December 31, 2023 and 2022 was a gain of $13.4 million and $1.6 million, respectively. These changes in the fair value during these periods impacted the associated liability on the consolidated balance sheets and recognition of the gain or loss was recognized in the gains (losses) on contingent consideration liabilities on the consolidated statements of operations. Refer to *Note 6 — Fair Value Measurements* for the valuation methodology and associated inputs.

On August 22, 2022, the Company entered into a management services agreement with Verde CO2 CCS, LLC ("Verde CO2") to provide general administrative and management services for carbon capture projects to BKVerde. Pursuant to the management services agreement, the Company was required to make fixed quarterly payments to Verde CO2 of $2.0 million. Payments began in August 2022 and on November 20, 2023, the Company and Verde CO2 terminated the management services agreement. Upon termination of this agreement, the Company is no longer required to make its quarterly payments to Verde CO2. Through December 31, 2023, the Company paid Verde CO2 $26.0 million.

A summary of the Company's commitments, excluding contingent consideration, as of December 31, 2023, is provided in the following table:

(in thousands)	2024	2025	2026	2027	2028	Thereafter	Total
Term loan payments	$114,000	$114,000	$114,000	$114,000	$ —	$ —	$456,000
Credit facilities	127,000	—	—	—	—	—	127,000
Interest payable	1,117	—	—	—	—	—	1,117
Notes payable to related party	—	—	—	75,000	—	—	75,000
Interest on related party notes	11,394	—	—	—	—	—	11,394
Operating lease payments	1,104	1,082	961	908	924	4,608	9,587
Volume commitments	53,542	33,214	31,376	23,477	17,704	49,566	208,879
Total	$308,157	$148,296	$146,337	$213,385	$18,628	$ 54,174	$888,977

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Notes to the Consolidated Financial Statements

Note 17 — Income Taxes

The Company's income tax (expense) benefit consisted of the following:

Tax (Expense) Benefit

(in thousands)	Year ended December 31, 2023	2022	2021
Current tax (expense) benefit			
United States federal income tax	$ —	$ 30,165	$(29,051)
Various state income taxes	4,169	(3,752)	(3,176)
Total current income tax (expense) benefit	4,169	26,413	(32,227)
Deferred tax (expense) benefit			
United States federal income tax	(29,569)	(86,772)	66,362
Various state taxes	(2,825)	(2,293)	6,391
Total deferred income tax (expense) benefit	(32,394)	(89,065)	72,753
Income tax (expense) benefit	$(28,225)	$(62,652)	$ 40,526

The following table reconciles the provision for income taxes using the federal statutory rate to the Company's effective tax rate:

Reconciliation of the Effective Tax Rate

(in thousands)	Year ended December 31, 2023	2022	2021
Income (loss) before income taxes	$145,143	$472,794	$(174,989)
Federal statutory rate	21.0%	21.0%	21.0%
Income tax (provision) benefit based on statutory rate	$ (30,480)	$ (99,287)	$ 36,748
(Increase) decrease in income taxes resulting from:			
State tax (expense) benefit, net of federal benefit	(4,002)	(9,948)	4,114
Change in state tax rate, net of federal effect	1,177	3,005	(227)
Deferred tax activity	—	—	520
Bargain purchase gain	—	38,139	—
Marginal well credit	94	6,417	—
Payable true-up	4,067	—	—
Other, including tax credits	919	(978)	(629)
Income tax (expense) benefit	$ (28,225)	$ (62,652)	$ 40,526

Deferred income taxes reflect the impact of temporary differences between assets and liabilities for financial reporting purposes and such amounts as measured by tax laws. The tax effect of the temporary differences giving rise to net deferred tax assets and liabilities is as follows:

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Notes to the Consolidated Financial Statements

Recognized Deferred Income Tax Assets and Liabilities

	As of December 31,	
(in thousands)	**2023**	**2022**
Deferred tax assets		
Fair value of derivative financial instruments	$ —	$ 49,869
Asset retirement obligations	43,578	41,315
Equity-based compensation	17,220	13,002
Contingent consideration	12,338	36,203
Interest expense carryforward	21,769	4,959
Net operating loss carryforward	27,583	4,231
Other(1)	10,387	6,345
Total deferred tax asset	$ 132,875	$ 155,924
Deferred tax liabilities		
Property and equipment	$(206,576)	$(211,892)
Investment in joint venture	(37,283)	(47,215)
Fair value of derivative financial instruments	(24,307)	—
Other(1)	(1,233)	(947)
Total deferred tax liability	$(269,399)	$(260,054)
Deferred tax liability, net	$(136,524)	$(104,130)

(1) Prior year's financial statement amounts have been reclassified between Deferred tax assets, other and Deferred tax liabilities, property and equipment, to conform with the presentation as of December 31, 2023. The reclassification was due the statutory rate decrease in the state of Pennsylvania, impacting other and property and equipment.

As of December 31, 2023, the Company has a net operating loss carryforward for federal tax purposes of approximately $27.6 million, which does not expire. In addition, the Company has Section 163(j) interest expense carryforwards of $21.8 million as of December 31, 2023. Section 382 of the Internal Revenue Code limits the use of net operating losses, which includes Section 163(j) interest expense carryforwards and tax credit carryforwards in certain situations where changes occur in the stock ownership of a company. If the company should have an ownership change of more than 50% of the value of its capital stock, utilization of these carryforwards could be restricted. As of December 31, 2023, the Company's net operating losses and Section 163(j) interest expense carryforwards are not currently subject to the limits of Section 382.

In assessing the realizability of deferred tax assets, management considers whether some portion or all of the deferred tax assets will be realized based on a more-likely-than-not standard of judgment. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which the Company's temporary differences become deductible. Management considers the scheduled reversal of deferred tax assets, projected future taxable income, and tax planning strategies in making this assessment. Accordingly, as of December 31, 2023 and 2022, the Company has not recognized a valuation allowance against its deferred tax assets.

The calculation of the Company's tax liabilities involves uncertainties in the application of complex tax laws and regulations. The Company recognizes those tax positions that it believes are more-likely-than-not to be sustained upon examination by the Internal Revenue Service or state revenue authorities. The Company has no unrecognized tax benefit balances as of December 31, 2023, 2022, and 2021. The Company is generally subject to potential federal and state examination for the tax years on and after December 31, 2021.

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Notes to the Consolidated Financial Statements

Note 18 — Earnings Per Share

The following is a reconciliation of the Company's basic weighted average number of common shares outstanding to the diluted weighted average number of common shares outstanding:

	Year Ended December 31,		
(in thousands)	**2023**	**2022**	**2021**
Basic weighted average common shares outstanding	60,730	58,659	58,496
Add: dilutive effect of TRSUs	172	351	—
Add: dilutive effect of PRSUs	3,478	2,980	—
Diluted weighted average of common shares outstanding	64,380	61,990	58,496
Weighted average number of outstanding securities excluded from the calculation of diluted loss per share			
TRSUs	—	—	237
PRSUs	—	—	711

Supplemental Oil and Gas Disclosures (unaudited)

The Company's operating natural gas properties are located solely in the United States.

Net Capitalized Costs Relating to Oil and Gas Producing Activities

The following table shows the capitalized costs of natural gas properties and the related accumulated depreciation, depletion, and amortization:

	As of December 31,	
(in thousands)	**2023**	**2022**
Developed properties	$2,370,156	$2,252,681
Undeveloped properties	15,846	15,511
Total capitalized costs	2,386,002	2,268,192
Less: Accumulated depreciation, depletion, and amortization	(560,016)	(363,832)
Net capitalized costs	$1,825,986	$1,904,360

Costs Incurred in Natural Gas and Oil Exploration and Development

The table below sets forth capitalized costs incurred in natural gas property acquisition, exploration, and development activities:

	For the year ended December 31,		
(in thousands)	**2023**	**2022**	**2021**
Undeveloped property acquisition costs	$ 335	$ 290	$ 3,569
Acquisitions(1)	9,885	431,897	2,928
Development costs	107,544	253,179	77,634
Total cost incurred	117,764	685,366	84,131
Asset retirement obligations(2)	89	38,337	923
Total costs incurred, including asset retirement obligations	$117,853	$723,703	$85,054

(1) For the year ended December 31, 2023, acquisition costs include the mineral interests in acquired wells and additional costs related to previous acquisitions.

(2) The amount as of December 31, 2022 includes $38.0 million related to the Exxon Barnett Acquisition.

The Company's results of operations from natural gas and oil producing activities are not materially different from the amounts presented within the consolidated statements of operations due to substantially all of the Company's operating activity relating to natural gas and oil producing activities. Accordingly, no supplemental disclosure information for the results of operations from natural gas and oil producing activities is included herein.

Natural Gas, NGL, and Oil Reserve Quantities

Estimates of the Company's total proved reserves are based on studies performed by the Company's internal engineering function and services provided by Ryder Scott, the Company's independent third-party reserve engineer. As of December 31, 2023, 2022, and 2021 the Company's estimates of total proved reserves are based on reserve reports prepared by Ryder Scott. Pricing for natural gas, NGLs, and oil is computed using the 12-month average index price, calculated as the unweighted arithmetic average for the first day of the month price for each month during the respective year. The process of estimating quantities of "proved" and "proved developed" and "proved undeveloped" natural gas, NGL, and oil reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering, and economic data. The Company's reserve reports also include estimates of asset retirement obligations for all properties for which an asset retirement obligation exists. Estimates for asset retirement obligations include all costs associated with abandonment after salvage. The data used in the Company's reserve reports may change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history, and continual reassessment of the viability of production under varying economic conditions. As a result, revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data make these estimates generally less precise than other estimates included within the consolidated financial statements.

The following tables illustrate the changes in the Company's quantities of net proved reserves:

	Natural Gas (MMcf)	NGL (MBbls)	Oil (MBbls)	Total (MMcfe)
January 1, 2021	1,985,532	107,234	723	2,633,274
Revision of previous estimates	828,360	45,234	258	1,101,312
Extensions and discoveries	645,338	13,722	58	728,018
Purchase of minerals in place	19,511	—	—	19,511
Improved recoveries	152,597	8,794	9	205,415
Production	(186,055)	(9,829)	(123)	(245,767)
December 31, 2021	3,445,283	165,155	925	4,441,763
Revision of previous estimates	(119,200)	(388)	43	(121,270)
Extensions and discoveries	364,494	30,037	786	549,432
Purchase of minerals in place	1,323,059	23,406	255	1,465,025
Improved recoveries	59,625	3,477	—	80,487
Production	(217,585)	(10,187)	(140)	(279,547)
December 31, 2022	4,855,676	211,500	1,869	6,135,890
Revision of previous estimates	(1,828,619)	(25,570)	(704)	(1,986,263)
Extensions and discoveries	188,572	6,539	—	227,806
Improved recoveries	16,632	2,250	5	30,162
Production	(249,766)	(10,554)	(119)	(313,804)
December 31, 2023	2,982,495	184,165	1,051	4,093,791
Proved developed reserves as of:				
January 1, 2022	2,494,925	151,433	867	3,408,725
December 31, 2022	3,798,027	170,840	1,111	4,829,733
December 31, 2023	2,443,072	156,399	992	3,387,418
Proved undeveloped reserves as of:				
January 1, 2022	950,358	13,722	58	1,033,038
December 31, 2022	1,057,649	40,660	758	1,306,157
December 31, 2023	539,423	27,766	59	706,373

	Developed	Undeveloped	Total
		(MMcfe)	
January 1, 2021	2,540,900	92,374	2,633,274
Revision of previous estimates	855,750	245,562	1,101,312
Extensions and discoveries	15,399	712,619	728,018
Purchase of minerals in place	17,664	1,847	19,511
Improved recoveries	205,415	—	205,415
Production	(245,767)	—	(245,767)
Undeveloped reserves converted to developed	19,364	(19,364)	—
December 31, 2021	3,408,725	1,033,038	4,441,763
Revision of previous estimates	234,914	(356,184)	(121,270)
Extensions and discoveries	74,094	475,338	549,432
Purchase of minerals in place	1,237,142	227,883	1,465,025
Improved recoveries	80,487	—	80,487
Production	(279,547)	—	(279,547)
Undeveloped reserves converted to developed	73,918	(73,918)	—
December 31, 2022	4,829,733	1,306,157	6,135,890
Revision of previous estimates	(1,191,886)	(794,377)	(1,986,263)
Extensions and discoveries	1,289	226,517	227,806
Improved recoveries	30,162	—	30,162
Production	(313,804)	—	(313,804)
Undeveloped reserves converted to developed	31,924	(31,924)	—
December 31, 2023	3,387,418	706,373	4,093,791

2023 Activity

During the year ended December 31, 2023, the Company’s proved reserves decreased by 2,042.1 Bcfe. The decrease in proved reserves was primarily attributable to decreased commodity pricing and changes in the Company’s drilling activity, which resulted in total downward revisions of 1,986.3 Bcfe. As discussed below, these decreases were partially offset by extensions and discoveries and improved recoveries experienced by the Company in 2023, which resulted in net increases to proved reserves of 227.8 Bcfe and 30.2 Bcfe, respectively. The Company produced 313.8 Bcfe during the year ended December 31, 2023.

Revisions of previous estimates — Primarily consisted of downward revisions to proved developed reserves and proved undeveloped reserves of 1,191.9 Bcfe and 273.1 Bcfe, respectively, as a result of lower average pricing during 2023 for natural gas, NGLs, and oil. Additional downward revisions were made to proved undeveloped reserves of 521.3 Bcfe due to the Company’s lower capital spend and the resulting reduction in drilling activity during 2023. Changes to the Company’s drilling schedule moved the development of 112.0 gross (104.6 net) locations in NEPA and the Barnett beyond the SEC requirement of developing PUDs five years from initial booking. These 112.0 gross (104.6 net) locations remain in the Company’s inventory of unproved locations to be developed outside of the next five years. The drilling schedule changes reflect the Company’s ongoing commitment to optimize the long-term plan to best develop its assets, maximize cash flow, and produce economic returns.

Extensions and discoveries — Primarily consisted of 226.5 Bcfe of proved undeveloped reserves, of which 197.8 Bcfe was attributable to 22.0 gross (21.2 net) locations recognized as a result of the Company’s optimized drilling program, which reduced costs and extended lateral lengths. In addition, 28.7 Bcfe was attributable to extensions related to 3.0 gross (1.1 net) locations in NEPA. The Company’s unitization and combination of acreage with Repsol resulted in the three additional locations.

Improved recoveries — Consisted of 30.2 Bcfe of proved developed reserves recognized as a result of the application of improved recovery techniques to producing wells during the year ended December 31, 2023.

Conversions of proved undeveloped reserves to proved developed reserves— Consisted of 31.9 Bcfe related to the completion of 22.0 gross (8.1 net) wells during the year ended December 31, 2023 that were converted to proved developed wells, previously classified as proved undeveloped.

2022 Activity

During the year ended December 31, 2022, the Company's proved reserves increased by 1,694.1 Bcfe. The increase in proved reserves was primarily due to the acquisition of the 2022 Barnett Assets. Other factors that contributed to the increase in proved reserves during the year ended December 31, 2022 included increasing commodity pricing, which improved economics, improved recoveries from application of restimulation technology to producing wells, and the addition of NGL rich locations to the drilling schedule. The Company produced 279.5 Bcfe during the year ended December 31, 2022.

Revisions of previous estimates — Consisted of upward revisions to proved developed reserves of 182.9 Bcfe as a result of higher average pricing during 2022 for natural gas, NGLs, and oil. An additional upward revision of 52.0 Bcfe was made to proved developed reserves for performance adjustments. Upward revisions were offset by downward revisions to proved undeveloped reserves of 246.0 Bcfe relating to 76.0 gross, (53.1 net) locations in the Marcellus and Barnett basins removed from the drilling schedule in exchange for locations with more favorable economics which are discussed in *2022 Activity — Extensions and discoverie*s. Additional downward revisions of 67.3 Bcfe and 42.9 Bcfe were made to proved undeveloped reserves related to performance and increased development costs, respectively.

Extensions and discoveries — Primarily consisted of the addition of 389.5 Bcfe of proved undeveloped reserves from 71.0 gross (66.4 net) locations recognized as a result of the Company's revised evaluation of properties acquired through our Devon Barnett Acquisition. These locations are more rich in NGLs than the previously recognized locations removed from the 2021 drilling schedule as discussed in *2022 Activity — Revisions of previous estimates.* Additional extensions consisted of proved undeveloped reserves of 85.8 Bcfe related to 27.0 gross (12.8 net) locations in the Marcellus and Barnett basins recognized from acreage acquired during 2021 and as a result of the revised 2022 drilling plan. Extensions related to proved developed reserves of 74.1 Bcfe consisted of 23.0 gross (13.0 net) newly drilled wells on locations previously classified as unproved.

Purchases of minerals in place— Consisted of 1,237.1 Bcfe and 227.9 Bcfe of proved developed and proved undeveloped reserves, respectively, from the Exxon Barnett Acquisition. The acquired reserves consisted of operated working interests in 2,289.0 gross (1,696.4 net) wells and 53.0 gross (48.7 net) undeveloped locations.

Improved recoveries — Consisted of 80.5 Bcfe of proved developed reserves recognized as a result of the application of improved recovery techniques to producing wells during the year ended December 31, 2022.

Conversions of proved undeveloped reserves to proved developed reserves — Consisted of 73.9 Bcfe related to the completion of 19.0 gross (5.5 net) wells on proved undeveloped locations during the year ended December 31, 2022.

2021 Activity

During the year ended December 31, 2021, the Company's proved reserves increased by 1,808.5 Bcfe. The increase in proved reserves was primarily due to increasing commodity pricing which improved economics, and additions to the drilling schedule for both proved developed and undeveloped reserves. The Company produced 245.8 Bcfe during the year ended December 31, 2021.

Revisions of previous estimates — Primarily consisted of upward revisions to proved developed reserves, and proved undeveloped reserves of 715.9 Bcfe and 245.6 Bcfe, respectively, as a result of higher average pricing during 2021 for natural gas, NGLs, and oil. The remaining upward adjustment of 139.8 Bcfe relates to upward performance adjustments to proved developed reserves of 219.2 Bcfe offset by a downward revision to proved developed reserves of 79.4 Bcfe due to increased production costs.

Extensions and discoveries — Upon completing the evaluation of properties acquired through the Company's Barnett Asset Acquisition, 550.1 Bcfe of proved undeveloped reserves was recognized for 123.0 gross (94.8 net) locations added to the Company's revised drilling schedule during 2021. Additional extensions consisted of proved undeveloped reserves of 162.5 Bcfe related to 13.0 gross (9.6 net) locations in the Marcellus Basin recognized from acquired acreage and the revised 2021 drilling plan. Extensions related to proved developed reserves of 15.4 Bcfe consisted of 10.0 gross (3.0 net) newly drilled wells.

Purchases of minerals in place — Consisted of 17.7 Bcfe of proved developed reserves from the acquisition of additional working interests in 601.0 gross (14.6 net) wells and 1.8 Bcfe of proved undeveloped reserves from the acquisition of additional working interest in 18.0 gross (1.0 net) locations, each of which were in addition to the Company's previously held working interests in wells or working interests in locations in the Barnett.

Improved recoveries — Consisted of 205.4 Bcfe of proved developed reserves recognized as a result of the application of improved recovery techniques to producing wells during the year ended December 31, 2021.

Conversions of proved undeveloped reserves to proved developed reserves — Consisted of 19.4 Bcfe related to the completion of 4.0 gross (3.9 net) wells on proved undeveloped locations during the year ended December 31, 2021.

Standardized Measure of Discounted Future Net Cash Flows

The following information has been developed based on natural gas, NGL, and oil reserve cash flows, including production volumes from the Company's reserve reports. It can be used for some comparisons but should not be the only method used to evaluate the Company or its performance. Further, the information in the following table may not represent realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Natural Gas Reserves ("Standardized Measure") be viewed as representative of the current value of the Company.

The following table details the Standardized Measure related to proved reserve as of the periods presented:

Future cash flows (in thousands)	**As of December 31,**		
	2023	**2022**	**2021**
Future cash inflows	$ 9,691,057	$ 34,992,383	$15,029,839
Future production costs	(5,799,209)	(11,967,176)	(6,840,969)
Future development costs[1]	(977,333)	(1,859,661)	(1,051,911)
Income tax expense	(406,937)	(4,572,275)	(1,501,984)
Future net cash flows	2,507,578	16,593,271	5,634,975
10% annual discount for estimated timing of cash flows	(1,445,245)	(9,599,669)	(3,222,086)
Standardized measure of discounted future net cash flows related to proved reserves	$ 1,062,333	$ 6,993,602	$ 2,412,889

(1) Includes abandonment costs

The following table summarizes the changes in the Standardized Measure:

	For the Year Ended December 31,		
(in thousands)	2023	2022	2021
Balance, beginning of period	$ 6,993,602	$ 2,412,889	$ 510,410
Net change in sales and transfer prices and in production (lifting) costs related to future production	(5,386,961)	4,656,150	1,768,893
Changes in estimated future development costs	91,657	43,101	(393,235)
Sales and transfers of natural gas, NGLs, and oil produced during the period	(201,884)	(1,293,492)	(522,403)
Net change due to extensions, discoveries, and improved recoveries	36,107	824,295	183,332
Purchase of minerals in place	—	1,649,737	19,050
Net change due to revisions in quantity estimates	(3,058,900)	(86,088)	1,266,086
Previously estimated development costs incurred during the period	27,598	37,784	60,406
Net change in future income taxes	1,790,684	(1,299,320)	(611,031)
Accretion of discount	861,914	322,498	56,096
Changes in timing and other	(91,484)	(273,952)	75,285
Total discounted cash flow as end of period	$ 1,062,333	$ 6,993,602	$2,412,889

BKV CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS
(in thousands, except per share amounts)
(Unaudited)

	June 30, 2024	December 31, 2023
Assets		
Current assets		
Cash and cash equivalents	$ 9,197	$ 25,407
Restricted cash	—	139,662
Accounts receivable, net	57,557	48,500
Accounts receivable, related parties	7,790	559
Commodity derivative assets, current	32,828	84,039
Other current assets	13,599	13,990
Total current assets	120,971	312,157
Natural gas properties and equipment		
Developed properties	2,245,194	2,370,156
Undeveloped properties	10,468	15,846
Midstream assets	275,997	318,855
Accumulated depreciation, depletion, and amortization	(620,424)	(579,415)
Total natural gas properties, net	1,911,235	2,125,442
Other property and equipment, net	86,876	83,935
Goodwill	18,417	18,417
Investment in joint venture	81,790	104,750
Commodity derivative assets	—	18,508
Other noncurrent assets	28,221	19,937
Total assets	$ 2,247,510	$ 2,683,146
Liabilities, mezzanine equity, and stockholders' equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 88,805	$ 149,173
Contingent consideration payable	23,606	20,000
Income taxes payable to related party	1,292	864
Credit facilities	—	127,000
Current portion of long-term debt, net	—	112,373
Other current liabilities	3,320	2,849
Total current liabilities	117,023	412,259
Asset retirement obligations	191,770	193,205
Contingent consideration	—	29,676
Note payable to related party	50,000	75,000
Deferred tax liability, net	94,724	136,524
Long-term debt, net	360,000	339,663
Other noncurrent liabilities	44,963	11,652
Total liabilities	858,480	1,197,979

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

BKV CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS
(in thousands, except per share amounts)
(Unaudited)

	June 30, 2024	December 31, 2023
Commitments and contingencies (Note 10)		
Mezzanine equity		
Common stock – minority ownership puttable shares; 2,481 authorized shares; 2,481 and 2,403 shares issued and outstanding as of June 30, 2024 and December 31, 2023, respectively	60,476	59,988
Equity-based compensation	129,412	126,966
Total mezzanine equity	189,888	186,954
Stockholders' equity		
Common stock, $0.01 par value; 300,000 authorized shares; 63,873 shares issued and outstanding as of June 30, 2024 and December 31, 2023	1,283	1,283
Treasury stock, shares at cost; 213 shares as of June 30, 2024 and December 31, 2023	(4,582)	(4,582)
Additional paid-in capital	1,033,355	1,034,144
Retained earnings	169,086	267,368
Total stockholders' equity	1,199,142	1,298,213
Total liabilities, mezzanine equity, and stockholders' equity	$ 2,247,510	$ 2,683,146

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

BKV CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share amounts)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2024	2023	2024	2023
Revenues and other operating income				
Natural gas, NGL, and oil sales	$125,854	$142,502	$ 267,541	$352,907
Midstream revenues	3,378	4,506	7,506	8,428
Derivative gains (losses), net	(7,486)	19,579	(11,165)	116,947
Marketing revenues	2,046	2,097	6,967	4,732
Gain on sales of assets	6,084	294	6,784	339
Related party and other	6,322	1,540	10,479	3,314
Total revenues and other operating income	136,198	170,518	288,112	486,667
Operating expenses				
Lease operating and workover	34,172	37,557	68,640	80,723
Taxes other than income	9,850	17,327	21,215	41,496
Gathering and transportation	53,714	62,302	113,105	120,586
Depreciation, depletion, amortization, and accretion	59,313	41,607	111,479	78,354
General and administrative	19,296	26,202	39,941	52,488
Other	3,034	5,983	11,276	8,483
Total operating expenses	179,379	190,978	365,656	382,130
Income (loss) from operations	(43,181)	(20,460)	(77,544)	104,537
Other income (expense)				
Gains (losses) on contingent consideration liabilities	(524)	16	6,070	22,910
Losses from equity affiliate	(15,253)	(8,876)	(22,960)	(14,275)
Loss on early extinguishment of debt	(13,877)	—	(13,877)	—
Interest income	1,771	488	3,404	1,136
Interest expense	(15,163)	(16,607)	(31,246)	(34,377)
Interest expense, related party	(1,879)	(1,591)	(3,852)	(3,083)
Other income	15	260	350	1,851
Income (loss) before income taxes	(88,091)	(46,770)	(139,655)	78,699
Income tax benefit (expense)	28,394	11,422	41,373	(17,885)
Net income (loss)	$ (59,697)	$ (35,348)	$ (98,282)	$ 60,814
Net income (loss) per common share:				
Basic	$ (0.90)	$ (0.60)	$ (1.48)	$ 1.03
Diluted	$ (0.90)	$ (0.60)	$ (1.48)	$ 0.97
Weighted average number of common shares outstanding:				
Basic	66,349	58,776	66,318	58,779
Diluted	66,349	58,776	66,318	62,434

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

BKV CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)
(Unaudited)

	Six Months Ended June 30, 2024	Six Months Ended June 30, 2023
Cash flows from operating activities:		
Net income (loss)	$ (98,282)	$ 60,814
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, amortization, and accretion	111,650	79,026
Equity-based compensation expense	2,145	10,295
Deferred income tax (benefit) expense	(41,800)	17,435
Unrealized (gains) losses on derivatives, net	79,100	(46,245)
Gains on contingent consideration liabilities	(6,070)	(22,910)
Settlement of contingent consideration	(20,000)	(65,000)
Proceeds from the sale of call options	23,502	—
Gain on sales of assets	(6,784)	(339)
Transaction costs from sales of assets	(3,898)	—
Losses from equity affiliate	22,960	14,275
Loss on extinguishment of debt	13,877	—
Other, net	1,778	1,565
Changes in operating assets and liabilities:		
Accounts receivable, net	(11,756)	103,952
Accounts payable and accrued liabilities	(48,891)	(68,275)
Other changes in operating assets and liabilities	(7,748)	(3,669)
Net cash provided by operating activities	9,782	80,924
Cash flows from investing activities:		
Acquisition of natural gas properties	—	(4,889)
Investment in other property and equipment	(8,233)	(12,365)
Development of natural gas properties	(21,509)	(113,090)
Proceeds from sales of assets	133,264	—
Loan advanced to equity affiliate	—	(8,000)
Other investing activities, net	(1,889)	9,738
Net cash provided by (used in) investing activities	101,633	(128,606)
Cash flows from financing activities:		
Payments on notes payable to related party	(25,000)	—
Payment on term loan agreement	(456,000)	(114,000)
Proceeds from draws on credit facilities	44,000	168,500
Payments on credit facilities	(171,000)	(132,500)
Proceeds under RBL Credit Agreement	425,000	—
Payment on RBL Credit Agreement	(65,000)	—
Payment of debt issuance costs	(8,054)	—
Debt extinguishment costs	(10,213)	—
Payments of deferred offering costs	(1,020)	(1,721)
Redemption of common stock issued upon vesting of equity-based compensation and other	—	(349)
Net share settlements, equity-based compensation	—	(2,955)
Net cash used in financing activities	(267,287)	(83,025)
Net decrease in cash, cash equivalents, and restricted cash	(155,872)	(130,707)
Cash, cash equivalents, and restricted cash, beginning of period	165,069	153,128
Cash and cash equivalents, end of period	$ 9,197	$ 22,421

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

BKV CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)
(Unaudited)

	Six Months Ended June 30,	
Supplemental cash flow information:	**2024**	**2023**
Cash payments for:		
Interest	$ 44,414	$ 33,544
Income tax	$ 6	$ 100
Non-cash investing and financing activities:		
Increase (decrease) in accrued capital expenditures	$ 1,296	$ (11,552)
Additions to asset retirement obligations	$ 21	$ 62
Lease liabilities arising from obtaining right-of-use assets	$ 494	$ —
Decrease in accrued offering costs	$ (341)	$ (200)
Adjustment of minority ownership puttable shares to redemption value	$ 488	$ 6,785
Adjustment of equity-based compensation to redemption value	$ 301	$ 9,762
Impact of redemption of shares issued in settlement of equity-based compensation and other on additional paid-in capital, common stock, and treasury stock	$ —	$ 527

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

BKV CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND MEZZANINE EQUITY
(in thousands)
(Unaudited)

	Stockholders' Equity						Mezzanine Equity			
	Common Stock						Common Stock			
	Shares	Amount	Treasury	Additional Paid-In Capital	Retained Earnings	Total Stock-holders' Equity	Shares	Amount	Equity-based Compensation	Total Mezzanine Equity
Balance, December 31, 2023	63,873	$1,283	$(4,582)	$1,034,144	$267,368	$1,298,213	2,403	$59,988	$126,966	$186,954
Net loss	—	—	—	—	(38,585)	(38,585)	—	—	—	—
Adjustment of minority ownership puttable shares to redemption value	—	—	—	(1,548)	—	(1,548)	—	1,548	—	1,548
Adjustment of equity-based compensation to redemption value	—	—	—	(495)	—	(495)	—	—	495	495
Common stock issued upon settlement of RSUs	—	—	—	—	—	—	69	—	—	—
Equity-based compensation	—	—	—	—	—	—	—	—	1,073	1,073
Balance, March 31, 2024	63,873	$1,283	$(4,582)	$1,032,101	$228,783	$1,257,585	2,472	$61,536	$128,354	$190,070
Net loss	—	—	—	—	(59,697)	(59,697)	—	—	—	—
Adjustment of minority ownership puttable shares to redemption value	—	—	—	1,060	—	1,060	—	(1,060)	—	(1,060)
Adjustment of equity-based compensation to redemption value	—	—	—	194	—	194	—	—	(194)	(194)
Common stock issued upon settlement of RSUs	—	—	—	—	—	—	9	—	—	—
Equity-based compensation	—	—	—	—	—	—	—	—	1,072	1,072
Balance, June 30, 2024	63,873	$1,283	$(4,582)	$1,033,355	$169,086	$1,199,142	$2,481	$60,476	$129,412	$189,888

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

BKV CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND MEZZANINE EQUITY
(in thousands)
(Unaudited)

	Stockholders' Equity						Mezzanine Equity			
	Common Stock						Common Stock			
	Shares	Amount	Treasury	Additional Paid-In Capital	Retained Earnings	Total Stock-holders' Equity	Shares	Amount	Equity-based Compensation	Total Mezzanine Equity
Balance, December 31, 2022	56,373	$1,132	$(3,974)	$896,433	$150,450	$1,044,041	2,290	$62,712	$ 89,171	$151,883
Net income	—	—	—	—	96,162	96,162	—	—	—	—
Redemption of common stock issued upon vesting of equity-based compensation and other	—	1	(527)	659	—	133	(18)	(2)	(525)	(527)
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income taxes	—	—	—	—	—	—	122	—	(2,736)	(2,736)
Adjustment of minority ownership puttable shares to redemption value	—	—	—	6,871	—	6,871	—	(6,871)	—	(6,871)
Adjustment of equity-based compensation to redemption value	—	—	—	10,346	—	10,346	—	—	(10,346)	(10,346)
Equity-based compensation	—	—	—	—	—	—	—	—	3,797	3,797
Balance, March 31, 2023	56,373	$1,133	$(4,501)	$914,309	$246,612	$1,157,553	2,394	$55,839	$ 79,361	$135,200
Net loss	—	—	—	—	(35,348)	(35,348)	—	—	—	—
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income taxes	—	—	—	—	—	—	11	—	(219)	(219)
Adjustment of minority ownership puttable shares to redemption value	—	—	—	(86)	—	(86)	—	86	—	86
Adjustment of equity-based compensation to redemption value	—	—	—	(584)	—	(584)	—	—	584	584
Equity-based compensation	—	—	—	—	—	—	—	—	6,498	6,498
Balance, June 30, 2023	56,373	$1,133	$(4,501)	$913,639	$211,264	$1,121,535	$2,405	$55,925	$ 86,224	$142,149

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

Note 1 — Business and Basis of Presentation

General

BKV Corporation (“BKV Corp”) was formed on May 1, 2020 and is a corporation registered with the State of Delaware. BKV Corp is a growth driven energy company focused on creating value for its shareholders through organic development of its properties, as well as accretive acquisitions. BKV Corp’s core business is to produce natural gas from its owned and operated upstream businesses.

The majority shareholder of BKV Corp is Banpu North America Corporation (“BNAC”). BKV Corp’s ultimate parent company is Banpu Public Company Limited, a public company listed in the Stock Exchange of Thailand. As of August 12, 2024, the date these condensed consolidated financial statements were available to be issued, BNAC owned 96.3% of BKV Corp’s shares. The remaining 3.7% of shares of common stock of BKV Corp were owned by non-controlling members of management, members of the board of directors, and employee and non-employee shareholders who hold shares with contingent put rights that may be exercised according to conditions stipulated in the agreement among these shareholders, BNAC, and BKV Corp.

Basis of Presentation of the Unaudited Condensed Consolidated Financial Statements

These condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (“GAAP”) and include the accounts for BKV Corp’s wholly owned subsidiaries. The condensed consolidated financial statements are unaudited and should be read in conjunction with the Company’s 2023 Consolidated Financial Statements (“Annual Financial Statements”) as certain disclosures and information required by GAAP for complete consolidated financial statements have been condensed or omitted. The condensed consolidated financial statements, in the opinion of management, reflect all adjustments, which include normal and recurring adjustments, necessary to fairly state the Company’s financial position, results of operations, and cash flows for the periods presented herein. The interim results are not necessarily indicative of results to be expected for the year ending December 31, 2024 or for any other future annual or interim period. The December 31, 2023 condensed consolidated balance sheet was derived from the audited Annual Financial Statements of the Company, but does not include all disclosures required by GAAP for annual financial statements.

BKV Upstream Midstream, LLC (“BKV Upstream Midstream”), a limited liability company, was formed on May 21, 2024 and registered in the state of Delaware. This entity is a wholly owned subsidiary of BKV Corp. Since its formation, all the midstream and upstream entities of BKV Corp are wholly owned subsidiaries of BKV Upstream Midstream and include BKV Operating, LLC, BKV Barnett, LLC, BKV Chelsea, LLC, BKV Midstream, LLC, BKV North Texas, LLC, and Kalnin Ventures, LLC.

On June 14, 2024, BKV sold BKV Chaffee Corners, LLC (“Chaffee”) and subsequently dissolved that entity, and on June 28, 2024, sold its non-operated upstream assets in BKV Chelsea, LLC (“Chelsea”). See *Note 3 — Natural Gas Properties & Other Property and Equipment* for further discussion.

Together, BKV Corp and its wholly owned subsidiaries are referred to collectively as “BKV” or the “Company.” All intercompany balances and transactions between these entities have been eliminated within the condensed consolidated financial statements. Current and deferred income taxes and related tax expense have been determined based on the stand-alone results of BKV by applying the separate return method to BKV’s operations as if it were a separate taxpayer. The Company is organized, managed, and identified as one operating segment and one reportable segment.

Reverse Stock Split

On October 30, 2023, the Company completed a one-for-two reverse stock split. As a result of the reverse stock split, every two shares of outstanding common stock were combined and now represent one share of common stock and fractional shares were paid out in cash to the common stockholders, which amounted to an immaterial amount. No fractional shares were issued in connection with the reverse stock split.

Following the reverse stock split, the Company's authorized capital stock consisted of 300,000,000 shares of common stock, $0.01 par value per share, of which 66,275,866 shares were issued and outstanding, and 80,000,000 shares of preferred stock, $0.01 par value per share, of which no shares were issued and outstanding. All shares of common stock issuable upon exercise of equity awards, as well as the applicable exercisable prices and weighted average fair value of the equity awards, and per share amounts contained throughout these condensed consolidated financial statements have been retroactively adjusted. See *Note 8 — Stockholders' Equity and Note 12 — Earnings Per Share for further discussion and analysis.*

Liquidity

As of June 30, 2024, the Company held $9.2 million of cash and cash equivalents. The Company's working capital as of June 30, 2024 was $3.9 million, and for the six months ended June 30, 2024, the Company's cash flows provided by operating activities was $13.7 million. The Company intends to make the payments related to its debt and investments in capital expenditures with cash flows from operations. During the six months ended June 30, 2024, the Company also sold call options with a counterparty, and received a premium of $23.5 million, and early terminated a portion of its derivative contracts and received cash on the gain of $13.3 million. For further discussion on the derivative transactions, see *Note 5 — Derivative Instruments*.

On June 11, 2024, BKV Upstream Midstream entered into the RBL Credit Agreement and drew down $425.0 million in revolver borrowings. The Company then repaid the amounts outstanding under the Term Loan Credit Agreement, the Revolving Credit Agreement and the SCB Credit Facility with proceeds from the loans under the RBL Credit Agreement and cash on hand. The Term Loan Credit Agreement, the Revolving Credit Agreement and the SCB Credit Facility were terminated concurrently with the repayment of the remaining amounts owed thereunder. See *Note 2 — Debt* for further discussion on the RBL Credit Agreement and these transactions.

On June 14, 2024, the Company sold its non-operated interests in Chaffee, a wholly owned subsidiary, for an aggregate purchase price of $106.7 million, subject to adjustment, and on June 28, 2024, sold its non-operated upstream assets in Chelsea for an aggregate purchase price of $25.0 million, subject to adjustment. See *Note 3 — Natural Gas Properties & Other Property and Equipment* for further discussion on these transactions.

Significant Judgments and Accounting Estimates

The preparation of these condensed consolidated financial statements in conformity with GAAP requires management to make certain estimates and assumptions that affect the amounts reported in the condensed consolidated financial statements and the accompanying notes. There have been no significant changes to the Company's accounting estimates from those disclosed in the Company's Annual Financial Statements.

Significant Accounting Policies

The Company's significant accounting policies are described in the notes to the consolidated financial statements for the year ended December 31, 2023 included in the Company's Annual Financial Statements. There have been no significant changes in accounting policies during the six months ended June 30, 2024.

Deferred Offering Costs

The Company has capitalized legal and other third party fees directly related to the Company's planned initial public offering ("IPO"). The deferred offering costs will be recorded as a reduction of the proceeds received from the IPO. If the IPO is abandoned or significantly delayed, the deferred offering costs will be expensed. As of June 30, 2024 and December 31, 2023, the Company capitalized $9.5 million and $8.9 million, respectively, of deferred offering costs, which are included within other noncurrent assets on the condensed consolidated balance sheets.

Restricted Cash

As of December 31, 2023, restricted cash included amounts to fund the debt service reserve account, which equaled the current portion of the Term Loan Credit Agreement plus accrued interest to comply with the Company's financial covenant under the Term Loan Credit Agreement. Due to the repayment of the Term Loan Credit Agreement, there was no restricted cash as of June 30, 2024. See *Note 2 — Debt*. The following table provides a reconciliation of cash, cash equivalents, and restricted cash to amounts shown in the condensed consolidated statements of cash flows:

(in thousands)	December 31, 2023
Cash and cash equivalents	$ 25,407
Restricted cash	139,662
Cash, cash equivalents, and restricted cash	$ 165,069

Common Shares Issued and Outstanding

As of June 30, 2024 and December 31, 2023, the Company had 66,353,545 and 66,275,866, respectively, of common shares issued and outstanding.

Note 2 — Debt

The following table summarizes the debt balances (refer to the Company's Annual Financial Statements for definitions and further description of the Company's debt instruments):

(in thousands)	June 30, 2024	December 31, 2023
Credit facilities		
SCB Credit Facility	$ —	$ 31,000
Revolving Credit Agreement	—	96,000
Term loan		
Current portion of Term Loan Credit Agreement	—	114,000
Current portion of unamortized debt issuance costs	—	(1,627)
Total current debt, net	—	239,373
RBL Credit Agreement	360,000	—
Term Loan Credit Agreement	—	342,000
Long-term portion of unamortized debt issuance costs	—	(2,337)
Total long-term debt, net	360,000	339,663
Total debt, net	$ 360,000	$ 579,036

On June 11, 2024 the Company paid down the outstanding balances, including interest, and concurrently terminated the SCB Credit Facility, the Revolving Credit Agreement, and the Term Loan Credit Agreement, with proceeds from the revolving borrowings on the RBL Credit Agreements and cash on hand. Due to the early termination of the Revolving Credit Agreement and the Term Loan Credit Agreement, the Company recorded a loss of $13.9 million, which was included in Loss on debt extinguishment in the condensed consolidated statements of operations during the three and six months ended June 30, 2024.

RBL Credit Agreement

On June 11, 2024, the Company and BKV Upstream Midstream entered into a reserved-based lending agreement (the "RBL Credit Agreement") with Citibank, N.A., as the administrative agent, and the financial institutions party thereto, with BKV Upstream Midstream as the borrower and BKV Corp as the guarantor on the RBL Credit Agreement. The RBL Credit Agreement includes a maximum credit commitment of $1.5 billion. As of June 11, 2024, the RBL Credit Agreement has a borrowing base of $800.0 million and an elected commitment of $600.0 million. The loans may be borrowed, repaid and reborrowed during the term of the RBL Credit Agreement. The RBL Credit Agreement matures on June 12, 2028. The obligations under the RBL Credit Agreement are secured and guaranteed on a secured basis by all of BKV Upstream Midstream's current and future material subsidiaries. Loans under the RBL Credit Agreement bear interest at one, three, or six-month term secured overnight financing rate ("SOFR") or an alternative base rate, as applicable, plus a credit spread adjustment of 0.10% for SOFR borrowings, plus an applicable margin per annum. Interest is payable on the last day of each interest period and at maturity. BKV Upstream Midstream is obligated to pay certain fees to the lenders and administrative agent under the RBL Credit Agreement, including commitment fees on the average daily amount of the undrawn portion of the commitments.

The RBL Credit Agreement contains various restrictive covenants that, among other things, limit BKV Upstream Midstream's ability and the ability of its restricted subsidiaries to, subject to certain exceptions: (i) incur indebtedness; (ii) incur liens; (iii) acquire or merge with any other company; (iv) sell assets or equity interests of its subsidiaries; (v) make investments; (vi) pay dividends or make other restricted payments; (vii) change its lines of business; (viii) enter into certain hedge agreements; (ix) enter into transactions with affiliates; (x) own any subsidiary that is not organized in the United States; (xi) prepay any unsecured senior or subordinated indebtedness; (xii) engage in certain marketing activities; and (xiii) allow, on a net basis, gas imbalances, take-or-pay or other prepayments with respect to our proved oil and gas properties. Beginning with the fiscal quarter ending September 30, 2024, the RBL Credit Agreement requires BKV Upstream Midstream to always hedge not less than 50% of projected production from our proved developed producing reserves for the subsequent 24 calendar month period immediately following such required delivery date.

The RBL Credit Agreement also includes financial covenants that require BKV Upstream Midstream to maintain:

- on a quarterly basis, a minimum Current Ratio (as defined in the RBL Credit Agreement) of no less than 1.00 to 1.00; and
- on a quarterly basis, a Net Leverage Ratio (as defined in the RBL Credit Agreement) of no greater than 3.25 to 1.00.

The RBL Credit Agreement includes customary equity cure rights that will enable BKV Upstream Midstream to cure certain breaches of the minimum current ratio covenant or the maximum net leverage ratio covenant.

The RBL Credit Agreement generally includes customary events of default for a reserve-based credit facility, some of which allow for an opportunity to cure. If an event of default relating to bankruptcy or other insolvency events occurs, the revolving loans will immediately become due and payable; if any other event of default exists, the administrative agent or the requisite lenders will be permitted to accelerate the maturity of the revolving loans. The RBL Credit Agreement is secured by substantially all of BKV Upstream Midstream's assets and those of the guarantors, and upon an event of default the agent under the RBL Credit Agreement could commence foreclosure proceedings.

On June 11, 2024, BKV Upstream Midstream drew down $425.0 million of revolving borrowings and on June 13, 2024, was issued $9.0 of letters of credit under the RBL Credit Agreement. Proceeds from the RBL Credit Agreement and cash on hand were used to repay outstanding balances of $456.0 million on the Term Loan Credit Agreement, $71.0 million on the Revolving Credit Agreement, and $15.0 million on the SCB Credit Facility, all which were terminated concurrently with the repayment of these outstanding borrowings and the related interest.

On June 27, 2024, BKV Upstream Midstream paid $65.0 million, including interest on the RBL Credit Agreement, leaving $231.0 million of available capacity thereunder for future borrowings and letters of credit as of June 30, 2024. On July 15, 2024, BKV Upstream Midstream drew down $20.0 million and on July 31, 2024 repaid $30.0 million. Then on August 5, 2024, BKV Upstream Midstream drew down another $10.0 million.

During the three and six months ended June 30, 2024 and 2023, BKV Upstream Midstream paid $8.1 million in financing costs, which have been deferred and capitalized as debt issuance costs included within other assets and are amortized over the life of the RBL Credit Agreement. As of June 30, 2024, $7.9 million of unamortized debt issuance costs remains outstanding. As of June 30, 2024, the effective interest rate on the RBL Credit Agreement was 8.68% and the outstanding letters of credit was $9.0 million.

Subordinated Intercompany Loan Agreement

On June 18, 2024, the Company also paid down $25.0 million of the $75.0 million outstanding on the $75 Million Loan Agreement with BNAC, including interest. As of June 30, 2024, the outstanding balance on the BNAC A&R Loan Agreement was $50.0 million with an effective interest rate of 10.4%.

Note 3 — Natural Gas Properties & Other Property and Equipment

Accumulated depreciation, depletion, and amortization for developed natural gas properties as of June 30, 2024 and December 31, 2023 was $606.4 million and $560.0 million, respectively. Depreciation, depletion, and amortization expense for developed natural gas properties was $53.0 million and $34.6 million for the three months ended June 30, 2024 and 2023, respectively, and $98.1 million and $64.9 million for the six months ended June 30, 2024 and 2023, respectively.

Accumulated depreciation for midstream assets as of June 30, 2024 and December 31, 2023 was $14.0 million and $19.4 million, respectively. Depreciation expense on midstream assets was $1.8 million and $1.9 million for the three months ended June 30, 2024 and 2023, respectively, and $3.7 million for both the six months ended June 30, 2024 and 2023.

Other property and equipment consisted of the following:

(in thousands)	June 30, 2024	December 31, 2023
Carbon capture, utilization, and sequestration	$ 63,836	$ 59,142
Buildings	15,707	15,707
Furniture, fixtures, equipment, and vehicles	15,175	15,101
Computer software	5,030	4,844
Land	3,090	3,090
Leasehold improvements	1,685	1,685
Construction in process	909	76
Total	105,432	99,645
Accumulated depreciation	(18,556)	(15,710)
Other property and equipment, net	$ 86,876	$ 83,935

Depreciation expense for other property and equipment was $1.5 million and $1.4 million for the three months ended June 30, 2024 and 2023, respectively, and $3.0 million and $2.8 million for the six months ended June 30, 2024 and 2023, respectively. During the three and six months ended June 30, 2024, the Company received proceeds on the sale of other properties and recognized a gain on sale of these properties of $0.7 million and $1.3 million, respectively, which are included in the gain on sales of assets in the condensed consolidated statements of operations.

Sales of BKV Chaffee Corners, LLC and BKV Chelsea, LLC

On June 14, 2024, the Company sold its wholly owned subsidiary, Chaffee, representing a non-operated interest in approximately 9,800 net acres and 116 gross (24.2 net) wells and 122 Bcfe of proved reserves in NEPA, as well as our interest in the Repsol Oil and Gas operated midstream system, for $106.7 million, subject to adjustment. The Company recognized a gain on the sale of $6.0 million, net of transaction costs of approximately $3.5 million, which is included in the gain on sales of assets in the condensed consolidated statements of operations. Final settlement date for the Chaffee sale is by October 14, 2024.

On June 28, 2024, Chelsea sold certain of its non-operated upstream assets, including interest in approximately 6,800 net acres and 214 gross (15.4 net) wells and 35 Bcfe of proved reserves in NEPA, for a purchase price of $25.0 million, subject to adjustment and transaction costs of approximately $0.4 million. Due to the immateriality of the upstream assets sold, the Company utilized the practical expedient to account for the sale of Chelsea's non-operated upstream assets sold as a normal retirement with no gain or loss recognized as sale of these assets did not significantly impact the depletion rate with respect to the total reserves retained in NEPA. Final settlement date for the Chelsea sale is by October 25, 2024.

Following the divestiture of these assets, the Company holds approximately 19,480 net acres in NEPA, approximately 98% of which is held by production.

Note 4 — Fair Value Measurements

As the Company uses the market approach to determine the fair value of its derivative instruments, these fair values are also compared to the values given by counterparties for reasonableness. Since natural gas and NGL swaps do not include optionality and therefore generally have no unobservable inputs, they are classified as Level 2. The Company factors its own non-performance risk into the valuation of derivatives using current published credit default swap rates. As of June 30, 2024 and December 31, 2023, the impact of the non-performance risk adjustment to the Company's fair value of commodity derivative liabilities was $3.9 million and $1.0 million, respectively.

Contingent consideration, minority ownership puttable shares, equity-based compensation, and assets acquired and liabilities assumed in the Exxon Barnett Acquisition are measured at fair value using Level 3 valuation techniques. There were no transfers between fair value levels during the three and six months ended June 30, 2024 and 2023.

The following tables set forth, by level within the fair value hierarchy, the financial assets and liabilities that were accounted for at fair value on a recurring basis:

	As of June 30, 2024		
	Fair Value Measurements Using:		
(in thousands)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Financial assets			
Derivative instruments	$ 32,828	$ —	$ 32,828
Financial liabilities			
Derivative instruments	32,883	—	32,883
Contingent consideration	—	23,606	23,606
Mezzanine equity			
Minority ownership puttable shares	—	60,476	60,476
Equity-based compensation	—	129,412	129,412

	As of December 31, 2023		
	Fair Value Measurements Using:		
(in thousands)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Financial assets			
Derivative instruments	$ 102,547	$ —	$102,547
Financial liabilities			
Contingent consideration	—	29,676	29,676
Mezzanine equity			
Minority ownership puttable shares	—	59,988	59,988
Equity-based compensation	—	126,966	126,966

The contingent consideration was generated from the 2019 acquisition of interest in proved reserves and related upstream assets in the Barnett formation from Devon Energy Corporation (the "Devon Barnett Acquisition") and the Exxon Barnett Acquisition. The fair value of the contingent consideration as of June 30, 2024 and December 31, 2023 represents management's best estimate if a third party were paid to assume the contingency. The fair values were determined using Monte Carlo simulations, which use observable (Level 2) inputs based on forecasted monthly Henry Hub Prices and West Texas Intermediate ("WTI") prices, as applicable, and unobservable (Level 3) inputs. The Exxon Barnett Acquisition and Devon Barnett Acquisition contingencies are described further in *Note 10 — Commitments and Contingencies.*

The minority ownership puttable shares were recorded at fair value upon initial recognition in mezzanine equity on the condensed consolidated balance sheets. The fair market value of the Company's common stock was used to determine the initial carrying value and redemption value of the minority ownership puttable shares in mezzanine equity on the condensed consolidated balance sheets as of June 30, 2024, and December 31, 2023. The Company's common stock was valued using both observable (Level 2) and unobservable (Level 3) inputs. The minority ownership puttable shares are further described in *Note 8 — Stockholders' Equity.*

Equity-based compensation is recorded at fair market value on the grant date. The underlying market condition was valued using the application of Monte Carlo simulations using both observable (Level 2) and unobservable (Level 3) inputs. The remaining components of the awards were valued based on the fair market value of the common stock of the Company, which is valued consistent with valuation methodologies described for the minority ownership puttable shares. As of June 30, 2024 and December 31, 2023, the fair market values of the Company's market condition and common stock were used to determine the redemption value or fair market value of equity-based compensation in mezzanine equity on the condensed consolidated balance sheets. Equity-based compensation is further described in *Note 8 — Stockholders' Equity.*

All per share amounts for common stock and equity-based compensation have been retrospectively restated to reflect the effect of the reverse stock split. Quantitative data regarding the Company's Level 3 unobservable inputs are as follows:

(in thousands, except per share amounts)	Fair Value	Valuation Technique	Unobservable Input	Range or Actual
Common stock – per share value, as of December 31, 2023(1)	$ 28.25	Enterprise value	Discount rate	11.5% – 12.5%
Contingent consideration, as of December 31, 2023	$ 29,676	Monte Carlo Simulation	Risk free rate(2)	5.2%
			Credit spread	4.7%
			Discount rate	9.9%
Common stock – per share value, as of March 31, 2024(1)	$ 28.98	Enterprise value	Discount rate	11.5% – 12.5%
Contingent consideration, as of March 31, 2024	$ 23,082	Monte Carlo Simulation	Risk free rate(2)	5.4%
			Credit spread	4.8%
			Discount rate	10.2%
Common stock – per share value, as of June 30, 2024(1)	$ 28.48	Enterprise value	Discount rate	11.5 – 12.5%
Contingent consideration, as of June 30, 2024	$ 23,606	Monte Carlo Simulation	Risk free rate(2)	5.2%
			Credit spread	4.8%
			Discount rate	10.0%

(1) The Company uses the midpoint of valuation results when estimating the fair value of common stock.

(2) Represents an observable input.

The table below sets forth the changes in the Company's Level 3 fair value measurements:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	**2024**	**2023**	**2024**	**2023**
Balance, beginning of period	$ 213,152	$ 200,358	$16,630	$ 39,934
Grant date fair value of equity-based compensation	1,072	6,279	2,145	6,815
Change in fair market value *(all instruments)*	(730)	653	(5,281)	(39,459)
Balance, end of period	$ 213,494	$ 207,290	$13,494	$207,290

Note 5 — Derivative Instruments

From time to time, the Company may utilize derivative contracts in connection with its natural gas and NGL operations to provide an economic hedge of the Company's exposure to commodity price risk associated with anticipated future natural gas and NGL production. The derivative contracts outstanding as of June 30, 2024 consisted of commodity swaps, basis swaps, call options, and producer collar agreements, subject to master netting agreements with each individual counterparty. The following table presents gross commodity derivative balances prior to applying netting adjustments recorded in the condensed consolidated balance sheets:

		As of June 30, 2024		
(in thousands)	**Balance Sheet Location**	**Gross Amounts of Assets and Liabilities**	**Offset Adjustments**	**Net Amounts of Assets and Liabilities**
Current derivative assets	Commodity derivative assets, current	$ 43,057	$ (10,229)	$ 32,828
Noncurrent derivative assets	Commodity derivative assets	3,976	(3,976)	—
Current derivative liabilities	Other current liabilities	10,229	(10,229)	—
Noncurrent derivative liabilities	Other noncurrent liabilities	36,859	(3,976)	32,883

		As of December 31, 2023		
(in thousands)	**Balance Sheet Location**	**Gross Amounts of Assets and Liabilities**	**Offset Adjustments**	**Net Amounts of Assets and Liabilities**
Current derivative assets	Commodity derivative assets, current	$ 90,540	$ (6,501)	$ 84,039
Noncurrent derivative assets	Commodity derivative assets	18,615	(107)	18,508
Current derivative liabilities	Other current liabilities	6,501	(6,501)	—
Noncurrent derivative liabilities	Other noncurrent liabilities	107	(107)	—

Collar, Commodity Swap, and Basis Swap Contracts

A commodity collar provides for a price floor and a price ceiling. The floating price for the collar contract is traded for a fixed price when the floating price is not between the floor and ceiling. If the floating price is between these contracted prices, no trade occurs. A commodity swap agreement is an agreement whereby a floating price based on the underlying commodity is traded for a fixed price over a specified period. Basis swaps provide a guaranteed price differential for natural gas from two different specified delivery points over a specified period. The fair value of open collar, commodity swap, and basis swap contracts reported in the condensed consolidated balance sheets may differ from that which would be realized in the event the Company terminated its position in the respective contract.

Derivative Contracts

The following tables set forth the derivative gains (losses), net on the condensed consolidated statements of operations:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	**2024**	**2023**	**2024**	**2023**
Total gain (loss) on settled derivatives	$ 31,471	$ 52,681	$ 67,935	$ 70,702
Total gain (loss) on unsettled derivatives	(38,957)	(33,102)	(79,100)	46,245
Total gain (loss) on derivatives, net	$ (7,486)	$ 19,579	$(11,165)	$116,947

Settled derivative gains, net for the six months ended June 30, 2024 includes gains of $13.3 million related to the termination of certain natural gas commodity derivative swap contracts prior to their contractual settlement dates. $8.4 million of such gains is attributable to early-terminated natural gas commodity derivative swap contracts covering production during the six months ended June 30, 2024. There were no early-terminated natural gas commodity derivative swap contracts during the three months ended June 30, 2024. Settled derivative gains (losses), net for the three and six months ended June 30, 2023 includes gains of $39.1 million related to the termination of certain natural gas commodity derivative swap and collar contracts prior to their contractual settlement dates. $8.5 million of such gains is attributable to early-terminated natural gas commodity derivative swap contracts covering production during the three and six months ended June 30, 2023.

On January 29, 2024, the Company entered into an agreement to sell a call option and subsequently received a net premium of $23.5 million for contracts that settle in 2026 and 2027. The call option has an established ceiling price. If at the time of settlement the contracted settlement price exceeds the ceiling price, the Company pays the counterparty an amount equal to the difference between the contracted settlement price and the ceiling price multiplied by the contract volumes. The premium received was recorded as a liability and is subsequently adjusted to the current fair value of the option written.

Volume of Derivative Activities

As of June 30, 2024, the Company's derivative activities based on volume and contract prices, categorized by primary underlying risk and related commodity, by year, were as follows:

The following table represents natural gas commodity derivatives indexed to NYMEX Henry Hub pricing:

Instrument	**MMBtu**	**Weighted Average Price (USD)**	**Weighted Average Price Floor**	**Weighted Average Price Ceiling**	**Fair Value as of June 30, 2024 (in thousands)**
2024					
Swap	45,517,500	$3.52			$ 27,577
2025					
Swap	60,800,000	$3.53			$ 3,699
Collars	14,600,000		$ 3.71	$ 4.11	$ 4,994
2026					
Swap	8,550,000	$3.53			$ (4,308)
Collars	25,550,000		$ 3.67	$ 4.19	$ 2,171
Call options	36,500,000			$ 5.00	$ (13,041)
2027					
Call options	36,500,000			$ 5.00	$ (14,306)

The following table represents natural gas basis derivatives based on the applicable basis reference price listed below:

Instrument	Basis Reference Price	MMBtu	Weighted Average Basis Differential	Fair Value as of June 30, 2024 (in thousands)
2024				
Swap	NGPL TXOK Basis	12,300,000	$ (0.54)	$ (1,009)
Swap	Transco Leidy Basis	16,560,000	$ (0.89)	$ 1,554

The following table represents natural gas liquids commodity derivatives for contracts, by contract type, expiring through March 31, 2026 based on the applicable index listed below:

Instrument	Commodity Reference Price	Gallons	Weighted Average Price (USD)	Fair Value as of June 30, 2024 (in thousands)
2024				
Swap	OPIS Purity Ethane Mont Belvieu	96,600,000	$0.23	$ 3,296
Swap	OPIS IsoButane Mont Belvieu Non-TET	6,568,800	$0.93	$ (1,137)
Swap	OPIS Normal Butane Mont Belvieu Non-TET	9,660,000	$0.90	$ (1,023)
Swap	OPIS Propane Mont Belvieu Non-TET	36,708,000	$0.80	$ (2,059)
Swap	OPIS Natural Gasoline Mont Belvieu Non-TET	15,456,000	$1.47	$ (1,552)
2025				
Swap	OPIS Purity Ethane Mont Belvieu	92,767,500	$0.25	$ (67)
Swap	OPIS IsoButane Mont Belvieu Non-TET	6,599,250	$0.87	$ (644)
Swap	OPIS Normal Butane Mont Belvieu Non-TET	9,082,500	$0.84	$ (629)
Swap	OPIS Propane Mont Belvieu Non-TET	35,385,000	$0.74	$ (1,539)
Swap	OPIS Natural Gasoline Mont Belvieu Non-TET	13,387,500	$1.39	$ (1,552)
2026				
Swap	OPIS Purity Ethane Mont Belvieu	6,615,000	$0.25	$ (218)
Swap	OPIS IsoButane Mont Belvieu Non-TET	472,500	$0.83	$ (33)
Swap	OPIS Normal Butane Mont Belvieu Non-TET	472,500	$0.80	$ (31)
Swap	OPIS Propane Mont Belvieu Non-TET	2,835,000	$0.69	$ (163)
Swap	OPIS Natural Gasoline Mont Belvieu Non-TET	945,000	$1.40	$ (35)

Note 6 — Revenue from Contracts with Customers

All of the Company's revenues are generated in the states of Pennsylvania and Texas. Revenues consist of the following:

	Three Months Ended June 30, 2024		
(in thousands)	Pennsylvania	Texas	Total
Natural gas	$ 5,453	$ 77,387	$ 82,840
NGLs	—	41,216	41,216
Oil	—	1,798	1,798
Total natural gas, NGL, and oil sales	5,453	120,401	125,854
Marketing revenues	—	2,046	2,046
Midstream revenues	771	2,607	3,378
Related party and other	—	6,322	6,322
Total	$ 6,224	$131,376	$137,600

(in thousands)	Three Months Ended June 30, 2023 Pennsylvania	Texas	Total
Natural gas	$ 11,255	$ 88,009	$ 99,264
NGLs	—	41,437	41,437
Oil	—	1,801	1,801
Total natural gas, NGL, and oil sales	11,255	131,247	142,502
Marketing revenues	—	2,097	2,097
Midstream revenues	939	3,567	4,506
Related party and other	—	1,540	1,540
Total	$ 12,194	$138,451	$150,645

(in thousands)	Six Months Ended June 30, 2024 Pennsylvania	Texas	Total
Natural gas	$ 17,945	$161,230	$179,175
NGLs	—	84,632	84,632
Oil	—	3,734	3,734
Total natural gas, NGL, and oil sales	17,945	249,596	267,541
Marketing revenues	—	6,967	6,967
Midstream revenues	2,014	5,492	7,506
Related party and other	—	10,479	10,479
Total	$ 19,959	$272,534	$292,493

(in thousands)	Six Months Ended June 30, 2023 Pennsylvania	Texas	Total
Natural gas	$ 38,526	$218,506	$257,032
NGLs	—	91,477	91,477
Oil	—	4,398	4,398
Total natural gas, NGL, and oil sales	38,526	314,381	352,907
Marketing revenues	—	4,732	4,732
Midstream revenues	2,285	6,143	8,428
Related party and other	—	3,314	3,314
Total	$ 40,811	$328,570	$369,381

Accounts receivable and revenue from contracts with customers

As of June 30, 2024 and December 31, 2023, the Company’s receivables from contracts with customers were $34.4 million and $32.8 million, respectively. Also, as of June 30, 2024 and December 31, 2023, one purchaser accounted for more than 10% of accounts receivables, and for the three months ended June 30, 2024 and 2023, that purchaser’s revenues were $71.8 million and $97.7 million, respectively, and for the six months ended June 30, 2024 and 2023, the same purchaser’s revenues were $168.2 million and $242.0 million, respectively. Another purchaser’s revenues, that also accounted for more than 10% of the Company’s revenues during the three months ended June 30, 2024 and 2023 amounted to $34.4 million and $38.3 million, respectively, and during the six months ended June 30, 2024 and 2023, amounted to $72.2 million and $82.9 million, respectively. The Company does not believe that the loss of these customers would have a material adverse effect on the condensed consolidated financial statements because alternative customers are readily available.

Note 7 — Accounts Payable and Accrued Liabilities

Accounts payable and accrued liabilities included in current liabilities consist of the following:

(in thousands)	June 30, 2024	December 31, 2023
Accounts payable	$ 38,080	$ 47,504
Accrued payroll	12,787	18,189
Oil and gas production and other taxes payable	14,364	48,857
Revenues payable	19,840	21,765
Other accrued liabilities	3,734	12,858
Total	$ 88,805	$ 149,173

Note 8 — Stockholders' Equity

Reverse Stock Split

On October 30, 2023, the Company completed a one-for-two reverse stock split. As a result of the reverse stock split, every two shares of outstanding common stock were combined and now represent one share of common stock and fractional shares were paid out in cash to the common stockholders, which amounted to an immaterial amount. No fractional shares were issued in connection with the reverse stock split.

Following the reverse stock split, the Company's authorized capital stock consisted of 300,000,000 shares of common stock, $0.01 par value per share, of which 66,275,866 shares were issued and outstanding and 80,000,000 shares of preferred stock, $0.01 par value per share, of which no shares were issued and outstanding. All shares of common stock issuable upon exercise and equity awards, as well as applicable exercisable prices, weighted average fair value of the equity awards, and per share amounts contained throughout this prospective have been retroactively adjusted for all past and current periods presented. On an as adjusted basis to give effect to the reverse stock split, the number of shares of common stock issued and outstanding as of June 30, 2024 and December 31, 2023 was 66,353,545 and 66,275,866, respectively.

Equity-Based Compensation

As of June 30, 2024, 7,724,499 restricted stock units ("RSUs") were considered to have been granted under Accounting Standards Codification ("ASC") 718 — Compensation — Stock Compensation ("ASC 718") from the Company's stock compensation plan (the "Plan") since January 1, 2021, the Plan's inception, when taking into consideration performance RSUs at the maximum performance level and time-based RSUs anticipated to be legally granted in the three years following inception. As of June 30, 2024, the awards granted under ASC 718 since inception equaled the number of RSUs legally granted.

Performance-Based Restricted Stock Units

PRSUs cliff vest and were subject to a vesting or performance period beginning January 1, 2021 and ending on December 31, 2023 (the "Performance Period"). As of December 31, 2023, or the Performance Period, the Company achieved its goals as follows: TSR met its threshold at 136%, ROCE met its threshold at 131%, and IPO readiness met its threshold at 200%. In February 2024, the Plan's committee approved the Company's goals and the PRSUs outstanding as of December 31, 2023 vested with some being forfeited prior to the Plan's approval.

(in thousands, except per share amounts)	Shares	Weighted-Average Grant Date Fair Value
Unvested PRSUs as of December 31, 2023	3,967	$ 19.02
Vested	(3,963)	$ 19.02
Forfeited	(4)	$ 19.02
Unvested PRSUs as of June 30, 2024	—	$ —

Due to the PRSU cliff vest, there was no equity-based compensation for the three and six months ended June 30, 2024. For the three and six months ended June 30, 2023, equity-based compensation related to the PRSUs was $5.4 million and $8.9 million, respectively. These costs were included in general and administrative expenses in the condensed consolidated statements of operations.

Time-Based Restricted Stock Units

The following table summarizes the TRSU activity for the six months ended June 30, 2024:

(in thousands, except per share amounts)	Shares	Weighted-Average Grant Date Fair Value
Unvested TRSUs as of December 31, 2023	727	$ 22.37
Vested[1]	(277)	$ 22.12
Forfeited	(20)	$ 22.12
Unvested TRSUs as of June 30, 2024	430	$ 22.37

(1) For the six months ended June 30, 2024, the total fair value of the shares vested was $28.48.

As of June 30, 2024, there was $11.1 million of unrecognized compensation expense related to the TRSU awards, which will be amortized over a weighted average period of 2.65 years.

For the three months ended June 30, 2024 and 2023, equity-based compensation expense related to the TRSUs was $1.0 million and $1.1 million, respectively. For the six months ended June 30, 2024 and 2023, equity-based compensation expense related to the TRSUs was $2.1 million and $1.4 million, respectively. These costs are included in general and administrative expenses in the condensed consolidated statements of operations.

Note 9 — Equity Method Investment

The Company is a 50% owner of BKV-BPP Power, LLC (the "Joint Venture"), which is accounted for as an equity method investment. On July 10, 2023, the Joint Venture acquired CXA Temple 2, LLC, the owner of 100% of the interests in Temple II, a combined cycle gas turbine and steam turbine power plant located on the same site as Temple I in the Electric Reliability Council of Texas North Zone in Temple, Texas for an aggregate purchase price of $460.0 million. Temple I and Temple II deliver power to customers on the ERCOT power network in Texas.

The Joint Venture has a term loan from its affiliates, BNAC and Banpu Power US Corporation ("BPPUS"), each in the amount of $141.0 million, which mature on November 1, 2026.

During the three months ended June 30, 2024 and 2023, the Company recognized, based on its 50% ownership interest in the Joint Venture, losses of $15.3 million and $8.9 million, respectively, and during the six months ended June 30, 2024 and 2023, the Company recognized losses of $23.0 million and $14.3 million, respectively.

The table below sets forth the summarized financial information of the Joint Venture:

Income Statement

(in thousands)	Three Months Ended June 30, 2024	Three Months Ended June 30, 2023	Six Months Ended June 30, 2024	Six Months Ended June 30, 2023
	(unaudited)		(unaudited)	
Total revenues, net	$ 86,801	$ 28,571	$171,771	$ 63,021
Operating expenses	99,382	41,670	182,584	80,545
Income (loss) from operations	(12,581)	(13,099)	(10,813)	(17,524)
Interest expense	(18,768)	(6,910)	(36,949)	(13,370)
Other income	843	2,255	1,842	2,343
Net loss	$ (30,506)	$ (17,754)	$ (45,920)	$(28,551)

Note 10 — Commitments and Contingencies

From time to time, the Company may be subject to various claims, title matters, and legal proceedings arising in the ordinary course of business, including environmental contamination claims, personal injury and property damage claims, claims related to joint interest billings and other matters under natural gas operating agreements, and other contractual disputes. The Company maintains general liability and other insurance to cover some of these potential liabilities. All known liabilities are fully accrued based on the Company's best estimate of the potential loss. While the outcome and impact on the Company cannot be predicted with certainty, for the periods presented in the condensed consolidated financial statements, the Company believes that its ultimate liability, with respect to any such matters, will not have a significant impact or material adverse effect on its financial positions, results of operations, or cash flows. Results of operations and cash flows, however, could be significantly impacted in the reporting periods in which such matters are resolved.

The Company has volume commitments in the form of gathering, processing, and transportation agreements with various third parties that require delivery of 1,310,269,187 dekatherms of natural gas. The significant majority of the agreements terminate by 2029, with one agreement extending through 2036. As of June 30, 2024, the aggregate undiscounted future payments required under these contracts total $354.1 million. The Company expects to fulfill the commitments from existing productive wells.

As a part of the consideration paid for the Devon Barnett Acquisition, additional cash consideration will be required to be paid by the Company if certain thresholds are met for average Henry Hub natural gas and WTI crude oil prices for each of the calendar years during the period beginning January 2021 through December 31, 2024 (the "Devon Barnett Earnout"). Average Henry Hub payouts and threshold are as follows: $2.75/MMBtu $20.0 million, $3.00/MMBtu $25.0 million, $3.25/MMBtu $35.0 million, and $3.50/MMBtu $45.0 million; average WTI payouts and thresholds are as follows for these periods: $50.00/Bbl $10.0 million, $55.00/Bbl $12.5 million, $60.00/Bbl $15.0 million, and $65.00/Bbl $20.0 million. The maximum remaining amount payable under the arrangement is $65.0 million for the year ending December 31, 2024. Payments are due in the month following the end of the respective measurement period for which the hurdle rates are set. On January 12, 2024, the Company paid the 2023 contingent consideration of $20.0 million. As described in *Note 4 — Fair Value Measurements*, management uses NYMEX forward pricing estimates for both Henry Hub and WTI hurdle rates and Monte Carlo simulations to determine the fair value of the contingent consideration. As of June 30, 2024 and December 31, 2023, the Company's estimate of the fair value of the unsettled contingent consideration was $23.6 million and $47.5 million, respectively. For the three months ended June 30,2024 and 2023, the change in the fair value of the contingent consideration was a loss of $0.7 million and $1.5 million, respectively, and for the six months ended June 30, 2024 and 2023, the change in the fair value of the contingent consideration was a gain of $3.9 million and $13.5 million, respectively. These changes in the fair value during these periods impacted the associated liability on the condensed consolidated balance sheets and recognition of the gain was recognized in the gains on contingent consideration liabilities on the condensed consolidated statements of operations.

In conjunction with the Exxon Barnett Acquisition, additional cash consideration will be required to be paid by the Company if certain thresholds for future Henry Hub natural gas prices are met for the year ended December 31, 2024. Payouts and thresholds are as follows for the year ended December 31, 2024: $3.75/MMBtu $10.0 million, $4.25/MMBtu $17.5 million, and $4.75/MMBtu $25.0 million. Payments of the additional cash consideration are due by January 31 of the calendar year following the applicable threshold measurement periods. The fair value of the contingent consideration as of June 30, 2024 was a negligible amount, and as of December 31, 2023 the fair value of the contingent consideration was $2.2 million. The change in the fair value of the contingent consideration for the three months ended June 30, 2024 and 2023 was a gain of $0.2 million and $1.5 million, respectively, and the change in the fair value of the contingent consideration for the six months ended June 30, 2024 and 2023 was a gain of $2.2 million and a $9.4 million, respectively. These changes in the fair value during these periods reduced the associated liability on the condensed consolidated balance sheets and recognition of the gain was recognized in the gains on contingent consideration liabilities on the condensed consolidated statements of operations. Refer to *Note 4 — Fair Value Measurements* for the valuation methodology and associated inputs.

A summary of the Company's commitments, excluding contingent consideration, as of June 30, 2024, is provided in the following table:

(in thousands)	2024	2025	2026	2027	2028	Thereafter	Total
RBL Credit Agreement	$ —	$ —	$ —	$ —	$360,000	$ —	$360,000
Interest payable	1,783	—	—	—	—	—	1,783
Notes payable to related party	—	—	—	50,000	—	—	50,000
Interest on related party notes	188	—	—	—	—	—	188
Operating lease payments	623	1,253	1,047	908	924	4,608	9,363
Volume commitments	34,512	68,228	66,356	58,639	53,144	73,185	354,064
Total	$37,106	$69,481	$67,403	$109,547	$414,068	$ 77,793	$775,398

Note 11 — Income Taxes

The effective tax rates for the three months ended June 30, 2024 and 2023 were (32.2)% and (24.4)%, respectively and for the six months ended June 30, 2024 and 2023 were (29.6)% and 22.7%, respectively. For the three and six months ended June 30, 2024, the difference in the effective tax rate from the U.S. statutory federal income tax rate of 21.0% was primarily due to the Company benefiting from the monetization of certain tax credits under the Internal Revenue Code ("IRC") Section 45Q from the injection of CO2 waste in the Barnett Zero well and from IRC Section 45I Marginal Well Credit from marginal production, and by state apportionment changes due to the sale of Chaffee. For the three and six months ended June 30, 2023, the difference in the effective tax rate from the U.S. statutory federal income tax rate of 21.0% was primarily due to state taxes.

Note 12 — Earnings Per Share

Basic net income (loss) per common share for each period is calculated by dividing net income (loss) by the basic weighted average number of common shares outstanding during the period. Diluted net income (loss) per common share is calculated by dividing net income (loss) of the Company by the diluted weighted average number of common shares outstanding for the respective period. Diluted weighted average number of common shares outstanding and the dilutive effect of potential common shares is calculated using the treasury method. The Company includes potential shares of common stock for PRSUs and TRSUs in the calculation of diluted weighted average shares outstanding based on the number of common shares that would be issuable if the end of the reporting period was also the end of the performance period. During periods in which the Company incurred a net loss, diluted weighted average common shares outstanding were equal to basic weighted average of common shares outstanding because the effects of all potential common shares was anti-dilutive.

The following is a reconciliation of the Company's basic weighted average number of common shares outstanding to the diluted weighted average number of common shares outstanding:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2024	2023	2024	2023
Basic weighted average common shares outstanding	66,349	58,776	66,318	58,779
Add: dilutive effect of TRSUs	—	—	—	156
Add: dilutive effect of PRSUs	—	—	—	3,499
Diluted weighted average of common shares outstanding	66,349	58,776	66,318	62,434
Weighted average number of outstanding securities excluded from the calculation of diluted loss per share:				
TRSUs	302	130	292	—
PRSUs	3,890	3,227	3,895	—

Events Subsequent to Original Issuance of Financial Statements

In connection with the reissuance of the Consolidated Financial Statements, the Company has evaluated the subsequent events occurring after April 29, 2024 through August 12, 2024, which represents the date the condensed consolidated financial statements were available to be issued. All such subsequent events are outlined below.

On April 30, 2024, the Company entered into an amendment to two existing transportation agreements to deliver an additional 683,575,000 dekatherms of natural gas through August 2029. The undiscounted future payments under these contracts are $11.5 million in 2024, $34.8 million in 2025, $35.0 million in 2026, $35.2 million in 2027, $35.4 million in 2028, and $23.6 million in 2029.

On April 30, 2024, the Company entered into the Fifth Amendment to the Term Loan Credit Agreement and the Fifth Amendment to the Revolving Credit Agreement with the respective lenders thereunder, pursuant to which such credit agreements were amended to (i) allow the Company to dispose all or a portion of the assets of BKV Chaffee Corners, LLC and all or a portion of the equity interests of BKV Chelsea, LLC to be made within 120 days after the effective date of the Fifth Amendment and (ii) require the ratable prepayment on the Term Loan Credit Agreement within three business days after net proceeds have been received from the disposal of stated properties, without a prepayment penalty.

On May 8, 2024, the Company drew down $14.0 million on the Revolving Credit Agreement, which was due on June 10, 2024.

On June 3, 2024, the Company repaid $4.0 million, including interest on the SCB Credit Facility.

On June 6, 2024, the Company repaid $16.0 million, including interest on the SCB Credit Facility.

On June 10, 2024, the Company repaid $14.0 million, including interest on the Revolving Credit Agreement.

On June 11, 2024, the Company entered into a four-year secured reserve-based lending agreement, which includes an elected commitment of $600.0 million. On June 11, 2024, BKV Upstream Midstream drew down $425.0 million of revolving borrowings and on June 13, 2024, was issued $9.0 of letters of credit under the RBL Credit Agreement. Proceeds from the RBL Credit Agreement and cash on hand were used to repay outstanding balances of $456.0 million on the Term Loan Credit Agreement, $71.0 million on the Revolving Credit Agreement, and $15.0 million on the SCB Credit Facility, all which were terminated concurrently with the repayment of these outstanding borrowings.

On June 14, 2024, the Company sold its wholly owned subsidiary, BKV Chaffee Corners, LLC, which owned a non-operated interest in approximately 9,800 net acres and 116 gross (24.2 net) wells and 122 Bcfe of proved reserves in NEPA, as well as our interest in the Repsol Oil & Gas operated midstream system, for a purchase price of $106.7 million, subject to adjustment.

On June 18, 2024, the Company paid down $25.0 million of the $75.0 million outstanding on the $75 Million Loan Agreement with BNAC, including interest.

On June 28, 2024, the Company's wholly owned subsidiary, BKV Chelsea, LLC, sold certain of its non-operated upstream assets, including its interest in approximately 6,800 net acres and 214 gross (15.4 net) wells and 35 Bcfe of proved reserves in NEPA for a purchase price of $25.0 million, subject to adjustment.

On June 27, 2024, the Company paid $65.0 million, including interest on the RBL Credit Agreement.

On July 15, 2024, BKV Upstream Midstream borrowed $20.0 million on the RBL Credit Agreement.

On July 31, 2024, BKV Upstream Midstream repaid $30.0 million on the RBL Credit Agreement.

On August 1, 2024, BKV Upstream Midstream was issued a $7.6 million letter of credit under the RBL Credit Agreement.

On August 5, 2024, BKV Upstream Midstream borrowed $10.0 million on the RBL Credit Agreement.

PART II

INFORMATION NOT REQUIRED IN PROSPECTUS

Item 13. Other Expenses of Issuance and Distribution.

The following table sets forth the various expenses, other than underwriting discounts and commissions, payable by us in connection with the offering of our common stock contemplated by this registration statement. All of the fees set forth below are estimates, except for the SEC registration fee, the Financial Industry Regulatory Authority, Inc. ("FINRA") filing fee and the NYSE listing fee.

SEC registration fee	$11,020
FINRA filing fee	15,500
NYSE listing fees	*
Transfer agent and registrar fees and expenses	*
Printing fees and expenses	*
Legal fees and expenses	*
Accounting fees and expenses	*
Engineering expenses	*
Miscellaneous	*
Total	$ *

* To be provided by amendment.

Item 14. Indemnification of Directors and Officers.

Our certificate of incorporation will provide that directors and officers will not be liable to the Company or its stockholders for monetary damages to the fullest extent permitted by the DGCL. In addition, if the DGCL is amended to authorize the further elimination or limitation of the liability of directors and officers, then the liability of a director or officer of the Company, in addition to the limitation on personal liability provided for in our certificate of incorporation, will be limited to the fullest extent permitted by the amended DGCL. Our bylaws will provide that the Company will indemnify, and advance expenses to, any officer or director to the fullest extent authorized by the DGCL.

Section 145 of the DGCL provides that a corporation may indemnify directors and officers as well as other employees and individuals against expenses, including attorneys' fees, judgments, fines and amounts paid in settlement in connection with specified actions, suits and proceedings whether civil, criminal, administrative, or investigative, other than a derivative action by or in the right of the corporation, if they acted in good faith and in a manner they reasonably believed to be in or not opposed to the best interests of the corporation and, with respect to any criminal action or proceeding, had no reasonable cause to believe their conduct was unlawful. A similar standard is applicable in the case of derivative actions, except that indemnification extends only to expenses, including attorneys' fees, incurred in connection with the defense or settlement of such action and the statute requires court approval before there can be any indemnification where the person seeking indemnification has been found liable to the corporation. The statute provides that it is not exclusive of other indemnification that may be granted by a corporation's certificate of incorporation, bylaws, disinterested director vote, stockholder vote, agreement or otherwise.

Our certificate of incorporation will also contain indemnification rights for our directors and our officers. Specifically, our certificate of incorporation will provide that we shall defend, indemnify and advance expenses to our officers and directors to the fullest extent authorized by the DGCL. Further, we may maintain insurance on behalf of our officers and directors against expense, liability or loss asserted incurred by them in their capacities as officers and directors.

In addition, we intend to enter into indemnification agreements, to be effective upon the completion of this offering, with our current directors and officers containing provisions that are in some respects broader than the specific indemnification provisions contained in the DGCL. The indemnification agreements will require us, among other things, to indemnify our directors and officers against certain liabilities that may arise by reason of their status or service as directors or officers and to advance their expenses incurred as a result of any proceeding against them as to which they could be indemnified. We also intend to enter into indemnification agreements with our future directors and officers.

We intend to maintain liability insurance policies that indemnify our directors and officers against various liabilities, including certain liabilities arising under the Securities Act or the Exchange Act that may be incurred by them in their capacity as such.

The proposed form of Underwriting Agreement to be filed as Exhibit 1.1 to this registration statement provides for indemnification of our directors and officers by the underwriters against certain liabilities arising under the Securities Act or otherwise in connection with this offering.

Insofar as indemnification for liabilities arising under the Securities Act may be permitted to directors, officers or persons controlling us pursuant to the foregoing provisions, we have been informed that in the opinion of the SEC, such indemnification is against public policy as expressed in the Securities Act and is therefore unenforceable.

Item 15. Recent Sales of Unregistered Securities.

In the three years preceding the filing of this registration statement, we have issued the following unregistered securities (without adjusting to give effect to our one-for-two reverse stock split completed on October 30, 2023, unless otherwise indicated).

Corporatization Event

The information set forth in "*Business — Our History — The Corporatization Event*" of the prospectus is incorporated herein by reference. On May 1, 2020, as part of the Corporatization Event, the Company issued 92,700,000 shares of its common stock in exchange for a contribution by the partners of BKV Oil and Gas Capital Partners, L.P. ("BKV O&G") of all of the partnership interests in BKV O&G and 2,000,000 shares of its common stock in exchange for a contribution by the members of Kalnin Ventures of all of the membership interests in Kalnin Ventures. The foregoing issuances were made under an exemption from registration provided by Section 4(a)(2) of the Securities Act, and no underwriters were involved in these transactions.

Other Equity Issuances

On October 1, 2020, the Company issued 22,284,000 shares of its common stock to an existing investor, BNAC, for $222.8 million. The foregoing issuance was made under an exemption from registration provided by Section 4(a)(2) of the Securities Act, and no underwriters were involved in this transaction.

On December 15, 2020, the Company issued 100,000 shares of its common stock to a new investor, OCM BKV Holdings, LLC, an affiliate of Oaktree Capital Management L.P., for $1.0 million, net of associated costs. These shares were issued in connection with the issuance of 9,900,000 shares of Series A Redeemable Preferred Stock, par value $10.00 per share, of the Company (the "Series A preferred stock"), to the same investor in a private placement for $99.0 million. The foregoing issuances were made under an exemption from registration provided by Section 4(a)(2) of the Securities Act and Rule 506(b) of Regulation D promulgated thereunder, and no underwriters were involved in these transactions. The Company redeemed a portion of such shares of Series A preferred stock in May 2021 and the remainder in October 2021.

2021 Plan Issuances

Share data in this paragraph is presented on an as-adjusted basis to effect to the one-for-two reverse stock split completed on October 30, 2023. From January 1, 2021 through December 31, 2021, performance restricted stock units (PRSUs) were legally granted under the 2021 Plan, which were scored in February 2024 and resulted in the vesting of 3,815,420 shares of the Company's common stock, and 328,235 time restricted stock units (TRSUs) were legally granted, of which 82,038 TRSUs were vested at the time of grant and 223,339 TRSUs have since vested. From January 1, 2022 through December 31, 2022, additional

PRSUs were legally granted, which were scored in February 2024 and resulted in the vesting of 146,326 shares of the Company's common stock, and 322,801 TRSUs were legally granted, of which 231,475 TRSUs were vested as of the date of this registration statement. From January 1, 2023 through December 31, 2023, no additional PRSUs were legally granted, and 316,558 TRSUs were legally granted, of which 150,791 TRSUs were vested as of the date of this registration statement. From January 1, 2024 through the date of this registration statement, 260,089 TRSUs were legally granted, of which 64,998 TRSUs were vested as of the date of this registration statement. Such awards under the 2021 Plan were granted to employees and directors of the Company or its subsidiaries. The foregoing issuances were made under an exemption from registration provided by either (i) Rule 701 under the Securities Act as transactions pursuant to compensatory benefit plans and contracts relating to compensation; or (ii) Section 4(a)(2) of the Securities Act as transactions by an issuer not involving any public offering. Any outstanding and unvested PRSUs and TRSUs will vest in connection with this offering.

2020 ESPP Issuances

In December 2021, the Company issued 287,209 shares of its common stock through sales under the 2020 ESPP and received proceeds of approximately $3.2 million from such sales. In April 2022, the Company issued 5,125 shares of its common stock through sales under the 2020 ESPP and received proceeds of $78,310 from such sales. Such sales under the 2020 ESPP were made to certain employees and directors of the Company. The foregoing issuances were made under an exemption from registration provided by either (i) Rule 701 under the Securities Act as transactions pursuant to compensatory benefit plans and contracts relating to compensation; or (ii) Section 4(a)(2) of the Securities Act as transactions by an issuer not involving any public offering.

2023 BNAC Equity Investment and Preemptive Rights Offering

In order to fund the Debt Service Reserve Account in the amount of $138.3 million pursuant to the requirements of a financial covenant in the Term Loan Credit Agreement, on September 27, 2023, the Company issued 15,000,000 shares of its common stock to an existing investor, BNAC, for $150.0 million, pursuant to the requirements of the existing stockholders' agreement. Subsequently, on September 29, 2023, pursuant to the preemptive rights provision contained in Article VI, Section 5 of the Company's existing bylaws, as amended and restated, the Company issued 521 shares of its common stock for $5,210, in the aggregate, to certain existing stockholders that qualified as an "accredited investor" within the meaning of Rule 501(a) of Regulation D promulgated under the Securities Act. The foregoing issuances were made under an exemption from registration provided by Rule 506(b) of Regulation D promulgated under the Securities Act, and no underwriters were involved in these transactions.

Item 16. Exhibits and Financial Statement Schedules.

(a) Exhibits: The list of exhibits set forth under "*Exhibit Index*" at the end of this registration statement is incorporated herein by reference.

Item 17. Undertakings.

The undersigned registrant hereby undertakes to provide to the underwriters at the closing specified in the Underwriting Agreement certificates in such denominations and registered in such names as required by the underwriters to permit prompt delivery to each purchaser.

Insofar as indemnification for liabilities arising under the Securities Act may be permitted to directors, officers and controlling persons of the registrant pursuant to the foregoing provisions, or otherwise, the registrant has been advised that in the opinion of the SEC such indemnification is against public policy as expressed in the Securities Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the registrant of expenses incurred or paid by a director, officer or controlling person of the registrant in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered, the registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Securities Act and will be governed by the final adjudication of such issue.

The undersigned registrant hereby undertakes that:

(1) For purposes of determining any liability under the Securities Act, the information omitted from the form of prospectus filed as part of this registration statement in reliance upon Rule 430A and contained in a form of prospectus filed by the registrant pursuant to Rule 424(b)(1) or (4) or 497(h) under the Securities Act shall be deemed to be part of this registration statement as of the time it was declared effective.

(2) For the purpose of determining any liability under the Securities Act, each post-effective amendment that contains a form of prospectus shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

EXHIBIT INDEX

Exhibit Number	Description
1.1**	Form of Underwriting Agreement
2.1**+‡	Purchase and Sale Agreement, dated December 17, 2019, between Devon Energy Production Company, L.P. and BKV Barnett, LLC
2.2**+	First Amendment to Purchase and Sale Agreement, dated April 13, 2020, among Devon Energy Production Company, L.P., BKV Barnett, LLC and, solely with respect to the sections listed therein, BKV Oil & Gas Capital Partners, L.P.
2.3**+	Purchase and Sale Agreement, dated May 18, 2022, between XTO Energy Inc., Barnett Gathering, LLC, BKV North Texas, LLC and BKV Midstream, LLC
2.4**+‡	Agreement of Sale and Purchase of Membership Interests, dated May 13, 2024, between BKV Corporation and Sabre Energy Development LLC
3.1**	Amended and Restated Certificate of Incorporation of BKV Corporation, as currently in effect
3.2**	Amended and Restated Bylaws of BKV Corporation, as currently in effect
3.3**	Form of Second Amended and Restated Certificate of Incorporation of BKV Corporation, to be in effect upon completion of this offering
3.4**	Form of Second Amended and Restated Bylaws of BKV Corporation, to be in effect upon completion of this offering
3.5**	First Amendment to Amended and Restated Certificate of Incorporation of BKV Corporation, as currently in effect
4.1**	Form of Common Stock Certificate
5.1**	Form of Opinion of Baker Botts L.L.P. as to the legality of the securities being registered
10.1**+	Credit Agreement, dated June 16, 2022, among BKV Corporation, the lenders party thereto and Bangkok Bank Public Company Limited, New York Branch
10.2**	Amended and Restated Loan Agreement, dated June 15, 2022, between Banpu North America Corporation and BKV Corporation, in the amount of $116,000,000
10.3**	Amended and Restated Loan Agreement, dated June 15, 2022, between Banpu North America Corporation and BKV Corporation, in the amount of $75,000,000
10.4**+	Revolving Credit Agreement, dated August 24, 2022, among BKV Corporation, the lenders party thereto and Bangkok Bank Public Company Limited, New York Branch
10.5**	Form of Stockholders' Agreement to be entered into between BKV Corporation and Banpu North America Corporation
10.6**	Form of Amended and Restated Tax Sharing Agreement to be entered into between BKV Corporation and Banpu North America Corporation
10.7**†‡	BKV Corporation 2021 Long Term Incentive Plan, adopted January 1, 2021 (the "2021 Plan")
10.8**†	First Amendment to the 2021 Plan, dated November 5, 2021
10.9**†‡	Form of Time Restricted Stock Unit Award and Performance-Based Restricted Stock Unit Award Notice and Award Agreement under the 2021 Plan
10.10**†	Form of Time Restricted Stock Unit Award Notice and Award Agreement under the 2021 Plan
10.11**†	BKV Corporation 2020 Employee Stock Purchase Plan, adopted July 16, 2020
10.12**†	First Amendment to the BKV Corporation 2020 Employee Stock Purchase Plan, dated November 5, 2021

Exhibit Number	Description
10.13**†	Second Amendment to the BKV Corporation 2020 Employee Stock Purchase Plan, dated April 21, 2022
10.14**†	Form of BKV Corporation 2022 Equity and Incentive Compensation Plan (the “2022 Plan”)
10.15**†‡	Form of Time Restricted Stock Unit Award and Performance-Based Restricted Stock Unit Award Notice and Award Agreement under the 2022 Plan (CEO)
10.16**†‡	Form of Time Restricted Stock Unit Award and Performance-Based Restricted Stock Unit Award Notice and Award Agreement under the 2022 Plan (Non-CEO Employee)
10.17**†	Form of Restricted Stock Unit Award Notice and Award Agreement under the 2022 Plan (Director)
10.18**†	Form of Director and Officer Indemnity Agreement
10.19**†	Employment Agreement, dated August 4, 2020, between BKV Corporation and Christopher P. Kalnin
10.20**†	Employment Agreement, dated January 11, 2021, between BKV Corporation and John T. Jimenez
10.21**†	Employment Agreement, dated February 18, 2020, between Kalnin Ventures LLC and Eric Jacobsen
10.22**†	Employment Agreement, dated January 15, 2021, between BKV Corporation and Brid Kealey
10.23**†	Employment Agreement, dated October 15, 2018, between Kalnin Ventures LLC and Lindsay B. Larrick
10.24**†	Employment Agreement, dated April 1, 2018, between Kalnin Ventures LLC and An Sao (Ethan) Ngo
10.25**+	Limited Liability Company Agreement of BKV-BPP Power, LLC, dated October 29, 2021
10.26**†	BKV Corporation Non-Employee Director Compensation Program
10.27**+	Credit Facility, dated December 22, 2021, among BKV Corporation, Oversea-Chinese Banking Corporation Limited and the guarantors party thereto
10.28**+	Credit Facility, dated February 7, 2022, among BKV Corporation, Standard Chartered Bank, BKV Chaffee Corners, LLC, BKV Chelsea, LLC, BKV Operating, LLC and BKV Barnett, LLC
10.29**	First Amendment, dated November 11, 2022, to Credit Agreement, dated June 16, 2022, among BKV Corporation, the lenders party thereto and Bangkok Bank Public Company Limited, New York Branch
10.30**	First Amendment, dated November 11, 2022, to Revolving Credit Agreement, dated August 24, 2022, among BKV Corporation, the lenders party thereto and Bangkok Bank Public Company Limited, New York Branch
10.31**†	Letter Agreement, dated November 14, 2022, between Kalnin Ventures, LLC and Barry Turcotte
10.32**	Amendment Letter, dated February 1, 2023, to Credit Facility, dated February 7, 2022, among BKV Corporation, Standard Chartered Bank, BKV Chaffee Corners, LLC, BKV Chelsea, LLC, BKV Operating, LLC and BKV Barnett, LLC
10.33**	Second Amendment, dated June 16, 2023, to Credit Agreement, dated June 16, 2022 and as amended on November 11, 2022, among BKV Corporation, the lenders party thereto and Bangkok Bank Public Company Limited, New York Branch
10.34**	Second Amendment, dated June 16, 2023, to Revolving Credit Agreement, dated August 24, 2022 and as amended on November 11, 2022, among BKV Corporation, the lenders party thereto and Bangkok Bank Public Company Limited, New York Branch

Exhibit Number	Description
10.35**	Letter Agreement Regarding Limited Waivers to Credit Agreement, dated as of June 16, 2023, among BKV Corporation, the lenders party thereto and Bangkok Bank Public Company Limited, New York Branch
10.36**	Letter Agreement Regarding Limited Waivers to Revolving Credit Agreement, dated as of June 16, 2023, among BKV Corporation, the lenders party thereto and Bangkok Bank Public Company Limited, New York Branch
10.37**	Letter Agreement Regarding Limited Waivers to Revolving Credit Agreement, dated as of July 6, 2023, among BKV Corporation, the lenders party thereto and Bangkok Bank Public Company Limited, New York Branch
10.38**	Third Amendment, dated July 18, 2023, to Credit Agreement, dated June 16, 2022 and as amended on November 11, 2022 and June 16, 2023, among BKV Corporation, the lenders party thereto and Bangkok Bank Public Company Limited, New York Branch
10.39**	Third Amendment, dated July 18, 2023, to Revolving Credit Agreement, dated August 24, 2022 and as amended on November 11, 2022 and June 16, 2023, among BKV Corporation, the lenders party thereto and Bangkok Bank Public Company Limited, New York Branch
10.40**	Fourth Amendment, dated September 29, 2023, to Credit Agreement, dated June 16, 2022 and as amended on November 11, 2022, June 16, 2023 and July 18, 2023, among BKV Corporation, the lenders party thereto and Bangkok Bank Public Company Limited, New York Branch
10.41**	Fourth Amendment, dated September 29, 2023, to Revolving Credit Agreement, dated August 24, 2022 and as amended on November 11, 2022, June 16, 2023 and July 18, 2023, among BKV Corporation, the lenders party thereto and Bangkok Bank Public Company Limited, New York Branch
10.42**†	Employment Agreement, effective October 9, 2023, between BKV Corporation and Mary Rita Valois
10.43**	Letter Agreement Regarding Limited Waivers to Revolving Credit Agreement, dated as of December 26, 2023, among BKV Corporation, the lenders party thereto and Bangkok Bank Public Company Limited, New York Branch
10.44**+	Credit Agreement dated as of June 11, 2024 among BKV Corporation, BKV Upstream Midstream, LLC, Citibank, N.A., and the Lenders party thereto
21.1**	List of Subsidiaries of BKV Corporation
23.1	Consent of PricewaterhouseCoopers LLP (BKV Corporation)
23.2	Consent of Ryder Scott Company, L.P.
23.4**	Consent of Baker Botts L.L.P. (included as part of Exhibit 5.1 hereto)
24.1**	Power of Attorney (included on the signature page of the initial filing of the registration statement)
24.2**	Power of Attorney for Barry S. Turcotte
24.3**	Power of Attorney for Kirana Limpaphayom
99.5	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2021 (SEC Pricing) (Barnett Assets)
99.6	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2021 (SEC Pricing) (Chaffee Corners Assets)
99.7	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2021 (SEC Pricing) (Chelsea Assets)
99.8	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2021 (SEC Pricing) (BKV Assets)

Exhibit Number	Description
99.9	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2022 (SEC Pricing) (Barnett Assets)
99.10	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2022 (SEC Pricing) (Chaffee Corners Assets)
99.11	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2022 (SEC Pricing) (Chelsea Assets)
99.12	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2022 (SEC Pricing) (BKV Assets)
99.13	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2022 (SEC Pricing) (North Texas Assets)
99.14	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2023 (SEC Pricing) (Total Company Assets)
99.15	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2023 (NYMEX Strip Pricing) (Total Company Assets)
107**	Calculation of Filing Fee Table

* To be filed by amendment.

** Previously filed.

† Compensatory plan or arrangement.

\+ Certain schedules and similar attachments have been omitted pursuant to Item 601(a)(5) of Regulation S-K. The registrant undertakes to furnish supplemental copies of any of the omitted schedules upon request by the SEC.

‡ Certain portions of this exhibit have been redacted pursuant to Item 601(b)(2)(ii) or Item 601(b)(10)(iv), as applicable, of Regulation S-K. The registrant agrees to furnish supplementally an unredacted copy of this exhibit to the SEC upon request.

SIGNATURES

Pursuant to the requirements of the Securities Act of 1933, the registrant has duly caused this registration statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Denver, State of Colorado, on this 12th day of August, 2024.

BKV CORPORATION

By: /s/ Christopher P. Kalnin
Christopher P. Kalnin
Chief Executive Officer

Pursuant to the requirements of the Securities Act of 1933, this registration statement has been signed by the following persons in the capacities and on the dates indicated.

Name	Title	Date
/s/ Christopher P. Kalnin Christopher P. Kalnin	Chief Executive Officer and Director (Principal Executive Officer)	August 12, 2024
* John T. Jimenez	Chief Financial Officer (Principal Financial Officer)	August 12, 2024
* Barry S. Turcotte	Chief Accounting Officer (Principal Accounting Officer)	August 12, 2024
* Chanin Vongkusolkit	Chairman of the Board	August 12, 2024
* Somruedee Chaimongkol	Director	August 12, 2024
* Joseph R. Davis	Director	August 12, 2024
* Akaraphong Dayananda	Director	August 12, 2024
* Kirana Limpaphayom	Director	August 12, 2024
* Carla S. Mashinski	Director	August 12, 2024
* Thiti Mekavichai	Director	August 12, 2024
* Charles C. Miller III	Director	August 12, 2024

Name	Title	Date
* Sunit S. Patel	Director	August 12, 2024
* Anon Sirisaengtaksin	Director	August 12, 2024
* Sinon Vongkusolkit	Director	August 12, 2024

*By: /s/ Christopher P. Kalnin
Christopher P. Kalnin
Attorney-in-fact

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the use in this Registration Statement on Form S-1 of BKV Corporation of our report dated April 29, 2024, relating to the financial statements of BKV Corporation, which appears in this Registration Statement. We also consent to the reference to us under the heading “Experts” in such Registration Statement.

/s/ PricewaterhouseCoopers LLP

Dallas, Texas
August 12, 2024

Exhibit 23.2

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

We hereby consent to the references to our firm in this Registration Statement on Form S-1 for BKV Corporation, and to the use of information from, and the inclusion of, our reports, (i) dated August 7, 2024, with respect to the estimates of proved reserves, future production and income attributable to certain leasehold and royalty interests of BKV Corporation referred to as the Barnett Assets as of December 31, 2021, (ii) dated August 7, 2024, with respect to the estimates of proved reserves, future production and income attributable to certain leasehold interests of BKV Corporation referred to as the Chaffee Corners Assets as of December 31, 2021, (iii) dated August 7, 2024, with respect to the estimates of proved reserves, future production and income attributable to certain leasehold interests of BKV Corporation referred to as the Chelsea Assets as of December 31, 2021, (iv) dated August 7, 2024, with respect to the estimates of proved reserves, future production and income attributable to certain leasehold interests of BKV Corporation referred to as the BKV Assets as of December 31, 2021, (v) dated August 7, 2024, with respect to the estimates of proved reserves, future production and income attributable to certain leasehold and royalty interests of BKV Corporation referred to as the Barnett Assets as of December 31, 2022, (vi) dated August 7, 2024, with respect to the estimates of proved reserves, future production and income attributable to certain leasehold interests of BKV Corporation referred to as the Chaffee Corners Assets as of December 31, 2022, (vii) dated August 7, 2024, with respect to the estimates of proved reserves, future production and income attributable to certain leasehold and royalty interests of BKV Corporation referred to as the Chelsea Assets as of December 31, 2022, (viii) dated August 7, 2024, with respect to the estimates of proved reserves, future production and income attributable to certain leasehold and royalty interests of BKV Corporation referred to as the BKV Assets as of December 31, 2022, (ix) dated August 7, 2024, with respect to the estimates of proved reserves, future production and income attributable to certain leasehold and royalty interests of BKV Corporation referred to as the North Texas Assets as of December 31, 2022, (x) dated August 7, 2024, with respect to the estimates of proved reserves, future production and income attributable to certain leasehold and royalty interests of BKV Corporation referred to as the Total Company Assets as of December 31, 2023, and (xi) dated August 7, 2024, with respect to the estimates of proved reserves, future production and income attributable to certain leasehold and royalty interests of BKV Corporation referred to as the Total Company Assets, using a NYMEX Alternate Pricing Scheme, as of December 31, 2023, each in this Registration Statement. We further consent to the reference to our firm under the heading "Experts" in this Registration Statement and related prospectus.

/s/ Ryder Scott Company
RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

Denver, Colorado
August 12, 2024

1100 LOUISIANA, SUITE 4600 HOUSTON, TEXAS 77002-5294 TEL (713) 651-9191 FAX (713) 651-0849
SUITE 2800, 350 7TH AVENUE, S.W. CALGARY, ALBERTA T2P 3N9 TEL (403) 262-2799

Exhibit 99.5

BKV CORPORATION

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

BARNETT ASSETS

SEC Parameters

As of

December 31, 2021

/s/ Stephen E. Gardner
Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

COLORADO LICENSED
STEPHEN E. GARDNER
44720
8/12/2024
PROFESSIONAL ENGINEER

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPELS REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

August 7, 2024

BKV Corporation
1200 17th Street, Suite 1850
Denver, CO 80202

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of BKV Corporation (BKV) referred to as the Barnett Assets as of December 31, 2021. The subject properties are located in the state of Texas. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on December 13, 2021 and presented herein, was prepared for public disclosure by BKV in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties referred to as the Barnett Assets evaluated by Ryder Scott account for a portion of BKV's total net proved reserves as of December 31, 2021. Based on information provided by BKV, the third party estimate conducted by Ryder Scott addresses approximately 79 percent of the total net proved reserves of BKV on a barrel of oil equivalent, BOE basis as of December 31, 2022. (Natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent.)

The estimated reserves and future net income amounts presented in this report, as of December 31, 2021 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, as required by the SEC regulations. Actual future prices may vary considerably from the prices that were used in this report. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

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SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
BKV Corporation
Barnett Assets
As of December 31, 2021

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Reserves				
Oil/Condensate – Mbbl	867	0	58	925
Plant Products – Mbbl	142,961	8,472	13,722	165,155
Gas – MMcf	1,882,781	148,214	468,762	2,499,757
Income Data ($M)				
Future Gross Revenue	$ 9,266,575	$ 668,814	$ 1,895,851	$ 11,831,240
Deductions	4,423,562	321,608	1,105,838	5,851,008
Future Net Income (FNI)	$ 4,843,013	$ 347,206	$ 790,013	$ 5,980,232
Discounted FNI @ 10%	$ 2,226,324	$ 106,070	$ 207,677	$ 2,540,071

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (Mbbl). All gas volumes are expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas volumes are located. All gas reserves volumes are reported on an "as sold" basis. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of BKV. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Gas reserves account for approximately 70 percent and liquid hydrocarbon reserves account for the remaining 30 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income ($M) As of December 31, 2021
Discount Rate Percent	Total Proved
8	$ 2,889,213
12	$ 2,263,496
15	$ 1,943,207
20	$ 1,570,202

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The proved developed non-producing reserves included herein consist of the behind pipe status category.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At BKV's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

BKV's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of reserves actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which BKV owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved, probable and possible reserves for the properties included herein were estimated by performance methods or analogy. All of the proved reserves attributable to producing wells and/or reservoirs were estimated by decline curve analysis, a performance method which utilized extrapolations of historical production and pressure data ending between May and September 2021, depending on the availability of data for a given case and in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

The reserves for the properties included herein attributable to the non-producing and the undeveloped status categories were estimated by analogy. The data utilized from the analogues were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

BKV has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by BKV with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, development costs, development plans, certain abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, and base maps. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by BKV. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For the producing wells included herein, our forecasts of future production rates and decline trends are based on the historical performance data of each well.

The initial performance of analogous wells was used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by BKV. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, well completions, and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period.

We furnished BKV with the above mentioned average prices in effect on December 31, 2021. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used for the geographic area included in the report.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, certain NGL fractionation and transportation fees, and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by BKV. The differentials furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the "average realized prices." The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves by reserves category for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
	Oil/Condensate	WTI Cushing	$66.56/bbl	$58.94/bbl
United States	NGLs	WTI Cushing	$66.56/bbl	$22.01/bbl
	Gas	Henry Hub	$3.598/MMBTU	$3.46/Mcf

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by BKV and are based on the operating expense reports of BKV and include only those costs directly applicable to the leases or wells. Certain gas gathering and transportation costs were included as operating expenses. The operating costs furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by BKV and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs.

The estimated net cost of abandonment after salvage was included for properties where certain abandonment costs net of salvage were provided by BKV, and which they requested be included in our report. The estimates of the net abandonment costs furnished by BKV were accepted without independent verification. We have made no inspections to determine if any other abandonment, decommissioning, and /or restoration costs may be necessary, in addition to the costs provided by BKV and included herein.

The proved developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with BKV's plans to develop these reserves as of December 31, 2021. The implementation of BKV's development plans as presented to us and incorporated herein is subject to the approval process adopted by BKV's management. As the result of our inquiries during the course of preparing this report, BKV has informed us that the development activities included herein have been subjected to and received the internal approvals required by BKV's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to BKV. BKV has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, BKV has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2021, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by BKV were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to BKV. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by BKV.

For filings made with the SEC under the 1933 securities Act, we have provided our written consent for the references to our name as well as to the references to our third party report in the registration statement on Form S-1 by BKV. Our consent for such use is included as a separate exhibit to the filings made with the SEC by BKV.

We have provided BKV with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by BKV and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

/s/ Stephen E. Gardner

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

SEG (DRO)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Stephen E. Gardner is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Gardner, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Gardner served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Gardner's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Mr. Gardner earned a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001 (summa cum laude). He is a licensed Professional Engineer in the States of Colorado and Texas. Mr. Gardner is a member of the Society of Petroleum Engineers and a former chairperson of the Society of Petroleum Evaluation Engineers for the Denver Chapter. He also currently serves on the latter organization's board of directors at the international level.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Gardner fulfills. As part of his 2020 continuing education hours, Mr. Gardner attended the annual Ryder Scott Reserves Conference, which covered a variety of reserves topics including analysis techniques for unconventional reservoirs, ESG and regulatory issues, reserves definitions and guidelines, SEC comment letter trends, and others. In addition, Mr. Gardner participated in various SPE and SPEE technical seminars, and other internal company training courses throughout the year, including one course in which he was the primary instructor, covering topics such as reserves evaluation methods and evaluation software, RTA/PTA, ethics, regulatory issues, greenhouse gas management, geothermal energy, and more.

Based on his educational background, professional training and more than 15 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Gardner has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

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

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

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

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

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

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

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

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

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

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

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

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

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

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing

Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In

Shut-in Reserves are expected to be recovered from:

(1)completion intervals that are open at the time of the estimate but which have not yet started producing;

(2)wells which were shut-in for market conditions or pipeline connections; or

(3)wells not capable of production for mechanical reasons.

Behind-Pipe

Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

> *(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.*
>
> *(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.*
>
> *(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.*

Exhibit 99.6

BKV CORPORATION

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

CHAFFEE CORNERS ASSETS

SEC Parameters

As of

December 31, 2021

/s/ Stephen E. Gardner

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

August 7, 2024

BKV Corporation
1200 17th Street, Suite 1850
Denver, CO 80202
Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold interests of BKV Corporation (BKV) referred to as the Chaffee Corners Assets as of December 31, 2021. The subject properties are located in the state of Pennsylvania. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on December 13, 2021 and presented herein, was prepared for public disclosure by BKV in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties referred to as the Chaffee Corners Assets evaluated by Ryder Scott account for a portion of BKV's total net proved reserves as of December 31, 2021. Based on information provided by BKV, the third party estimate conducted by Ryder Scott addresses approximately 2 percent of the total net proved reserves of BKV on a barrel of oil equivalent, BOE basis as of December 31, 2022. (Natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent.)

The estimated reserves and future net income amounts presented in this report, as of December 31, 2021 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, as required by the SEC regulations. Actual future prices may vary considerably from the prices that were used in this report. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold Interests of
BKV Corporation
Chaffee Corners Assets
As of December 31, 2021

	Proved			
	Developed			Total
	Producing	Non-Producing(1)	Undeveloped	Proved
Net Reserves				
Gas – MMcf	64,993	0	6,499	71,492
Income Data ($M)				
Future Gross Revenue	$ 220,106	$ 0	$ 22,013	$ 242,119
Deductions	69,642	57	9,819	79,518
Future Net Income (FNI)	$ 150,464	$ (57)	$ 12,194	$ 162,601
Discounted FNI @ 10%	$ 75,049	$ (53)	$ 4,069	$ 79,065

(1) Negative values for Future Net Income and Discounted FNI are due to abandonment liability.

All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software packageARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of BKV. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes, but in the state of Pennsylvania, these taxes are zero. The deductions incorporate the normal direct costs of operating the wells, the Pennsylvania Impact Fee (presented herein as ad valorem taxes), development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Gas reserves account for 100 percent of the total future gross revenue from the proved reserves reported herein

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income ($M) As of December 31, 2021
Discount Rate Percent	Total Proved
8	$ 88,256
12	$ 71,663
15	$ 62,948
20	$ 52,574

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission’s Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled “PETROLEUM RESERVES DEFINITIONS” is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled “PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES” in this report. The negative values of future net income and discounted FNI shown in the proved developed non-producing category comprise shut-in wells with only an abandonment liability.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are “estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations.” All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At BKV's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

BKV's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which BKV owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator.

When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved, probable and possible reserves for the properties included herein were estimated by performance methods or analogy. All of the proved reserves attributable to producing wells and/or reservoirs were estimated by decline curve analysis, a performance method which utilized extrapolations of historical production and pressure data ending between June and September 2021, depending on the availability of data for a given case and in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

The reserves for the properties included herein attributable to the undeveloped status category were estimated by analogy. The data utilized from the analogues were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

BKV has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by BKV with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, the Pennsylvania Impact Fee, development costs, development plans, certain abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, and base maps. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by BKV. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For the producing wells included herein, our forecasts of future production rates and decline trends are based on the historical performance data of each well.

The initial performance of analogous wells was used to estimate the anticipated initial production rates for those locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by BKV. Locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, well completions, and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period.

We furnished BKV with the above mentioned average prices in effect on December 31, 2021. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used for the geographic area included in the report.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees**,** and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by BKV. The differentials furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose.

In addition, the table below summarizes the net volume weighted benchmark price adjusted for differentials and referred to herein as the "average realized prices." The average realized price shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves by reserves category for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Price	Average Realized Price
North America	Gas	Henry Hub	$3.598/MMBTU	$3.39/Mcf

The effects of derivative instruments designated as price hedges of gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by BKV and are based on the operating expense reports of BKV and include only those costs directly applicable to the leases or wells. The operating costs furnished by BKV were reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by BKV to determine these costs. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by BKV and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by BKV were reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by BKV to determine these costs.

The estimated net cost of abandonment after salvage was included for properties where certain abandonment costs net of salvage were provided by BKV, and which they requested be included in our report. The estimates of the net abandonment costs furnished by BKV were accepted without independent verification. We have made no inspections to determine if any other abandonment, decommissioning, and /or restoration costs may be necessary, in addition to the costs provided by BKV and included herein.

The proved undeveloped reserves in this report have been incorporated herein in accordance with BKV's plans to develop these reserves as of December 31, 2021. The implementation of BKV's development plans as presented to us and incorporated herein is subject to the approval process adopted by BKV's management. As the result of our inquiries during the course of preparing this report, BKV has informed us that the development activities included herein have been subjected to and received the internal approvals required by BKV's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to BKV. BKV has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, BKV has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2021, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by BKV were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to BKV. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott.The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by BKV.

For filings made with the SEC under the 1933 securities Act, we have provided our written consent for the references to our name as well as to the references to our third party report in the registration statement on Form S-1 by BKV. Our consent for such use is included as a separate exhibit to the filings made with the SEC by BKV.

We have provided BKV with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by BKV and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

/s/ Stephen E. Gardner

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

SEG (DRO)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Stephen E. Gardner is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Gardner, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Gardner served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Gardner's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Mr. Gardner earned a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001 (summa cum laude). He is a licensed Professional Engineer in the States of Colorado and Texas. Mr. Gardner is a member of the Society of Petroleum Engineers and a former chairperson of the Society of Petroleum Evaluation Engineers for the Denver Chapter. He also currently serves on the latter organization's board of directors at the international level.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Gardner fulfills. As part of his 2020 continuing education hours, Mr. Gardner attended the annual Ryder Scott Reserves Conference, which covered a variety of reserves topics including analysis techniques for unconventional reservoirs, ESG and regulatory issues, reserves definitions and guidelines, SEC comment letter trends, and others. In addition, Mr. Gardner participated in various SPE and SPEE technical seminars, and other internal company training courses throughout the year, including one course in which he was the primary instructor, covering topics such as reserves evaluation methods and evaluation software, RTA/PTA, ethics, regulatory issues, greenhouse gas management, geothermal energy, and more.

Based on his educational background, professional training and more than 15 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Gardner has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal

methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): *Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).*

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

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

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

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

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

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

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

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

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

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

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

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made toTitle 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

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

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

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing

Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In

Shut-in Reserves are expected to be recovered from:

(1)completion intervals that are open at the time of the estimate but which have not yet started producing;

(2)wells which were shut-in for market conditions or pipeline connections; or

(3)wells not capable of production for mechanical reasons.

Behind-Pipe

Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

> *(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.*
>
> *(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.*
>
> *(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.*

Exhibit 99.7

BKV CORPORATION

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold Interests

CHELSEA ASSETS

SEC Parameters

As of

December 31, 2021

/s/ Stephen E. Gardner
Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPELS REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

August 7, 2024

BKV Corporation
1200 17th Street, Suite 1850
Denver, CO 80202

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold interests of BKV Corporation (BKV) referred to as the Chelsea Assets as of December 31, 2021. The subject properties are located in the state of Pennsylvania. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on December 13, 2021 and presented herein, was prepared for public disclosure by BKV in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties referred to as the Chelsea Assets evaluated by Ryder Scott account for a portion of BKV's total net proved reserves as of December 31, 2021. Based on information provided by BKV, the third party estimate conducted by Ryder Scott addresses approximately 8 percent of the total net proved reserves of BKV on a barrel of oil equivalent, BOE basis as of December 31, 2022. (Natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent.)

The estimated reserves and future net income amounts presented in this report, as of December 31, 2021 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, as required by the SEC regulations. Actual future prices may vary considerably from the prices that were used in this report. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

1100 LOUISIANA, SUITE 4600 HOUSTON, TEXAS 77002-5294 TEL (713) 651-9191
SUITE 2800, 350 7TH AVENUE, S.W. CALGARY, ALBERTA T2P 3N9 TEL (403) 262-2799

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold Interests of
BKV Corporation
Chelsea Assets
As of December 31, 2021

	Proved							
	Developed						Total	
	Producing		Non-Producing[1]		Undeveloped		Proved	
Net Reserves								
Gas – MMcf		198,498		0		174,139		372,637
Income Data ($M)								
Future Gross Revenue	$	548,433	$	0	$	484,880	$	1,033,313
Deductions		326,523		352		288,102		614,977
Future Net Income (FNI)	$	221,910	$	(352)	$	196,778	$	418,336
Discounted FNI @ 10%	$	130,841	$	(322)	$	65,149	$	195,668

(1) Negative values for Future Net Income and Discounted FNI are due to abandonment liability.

All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software packageARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of BKV. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes, but in the state of Pennsylvania, these taxes are zero. The deductions incorporate the normal direct costs of operating the wells, the Pennsylvania Impact Fee (presented herein as ad valorem taxes), development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Gas reserves account for 100 percent of the total future gross revenue from the proved reserves reported herein

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

Discount Rate Percent	Discounted Future Net Income ($M) As of December 31, 2021 Total Proved	
8	$	221,047
12	$	175,026
15	$	150,522
20	$	121,204

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The negative values of future net income and discounted FNI shown in the proved developed non-producing category comprise shut-in wells with only an abandonment liability.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At BKV's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

BKV's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of reserves actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which BKV owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The reserves for the properties included herein were estimated by performance methods or analogy. All of the proved reserves attributable to producing wells and/or reservoirs were estimated by decline curve analysis, a performance method which utilized extrapolations of historical production and pressure data ending between June and September 2021, depending on the availability of data for a given case and in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

The reserves for the properties included herein attributable to the undeveloped status category were estimated by analogy. The data utilized from the analogues were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

BKV has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by BKV with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, the Pennsylvania Impact Fee, development costs, development plans, certain abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, and base maps. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by BKV. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For the producing wells included herein, our forecasts of future production rates and decline trends are based on the historical performance data of each well.

The initial performance of analogous wells was used to estimate the anticipated initial production rates for those locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by BKV. Locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, well completions, and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period.

We furnished BKV with the above mentioned average prices in effect on December 31, 2021. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used for the geographic area included in the report.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees, and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by BKV. The differentials furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose.

In addition, the table below summarizes the net volume weighted benchmark price adjusted for differentials and referred to herein as the "average realized prices." The average realized price shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves by reserves category for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Price	Average Realized Price
North America	Gas	Henry Hub	$3.598/MMBTU	$2.77/Mcf

The effects of derivative instruments designated as price hedges of gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by BKV and are based on the operating expense reports of BKV and include only those costs directly applicable to the leases or wells. The operating costs furnished by BKV were reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by BKV to determine these costs. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by BKV and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by BKV were reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by BKV to determine these costs.

The estimated net cost of abandonment after salvage was included for properties where certain abandonment costs net of salvage were provided by BKV, and which they requested be included in our report. The estimates of the net abandonment costs furnished by BKV were accepted without independent verification. We have made no inspections to determine if any other abandonment, decommissioning, and /or restoration costs may be necessary, in addition to the costs provided by BKV and included herein.

The proved undeveloped reserves in this report have been incorporated herein in accordance with BKV's plans to develop these reserves as of December 31, 2021. The implementation of BKV's development plans as presented to us and incorporated herein is subject to the approval process adopted by BKV's management. As the result of our inquiries during the course of preparing this report, BKV has informed us that the development activities included herein have been subjected to and received the internal approvals required by BKV's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to BKV. BKV has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, BKV has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2021, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by BKV were held constant throughout the life of the properties.

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to BKV. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott.The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by BKV.

For filings made with the SEC under the 1933 securities Act, we have provided our written consent for the references to our name as well as to the references to our third party report in the registration statement on Form S-1 by BKV. Our consent for such use is included as a separate exhibit to the filings made with the SEC by BKV.

We have provided BKV with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by BKV and the original signed report letter, the original signed report letter shall control and supersede the digital version.

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

/s/ Stephen E. Gardner

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

SEG (DRO)/pl

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Stephen E. Gardner is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Gardner, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Gardner served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Gardner's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Mr. Gardner earned a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001 (summa cum laude). He is a licensed Professional Engineer in the States of Colorado and Texas. Mr. Gardner is a member of the Society of Petroleum Engineers and a former chairperson of the Society of Petroleum Evaluation Engineers for the Denver Chapter. He also currently serves on the latter organization's board of directors at the international level.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Gardner fulfills. As part of his 2020 continuing education hours, Mr. Gardner attended the annual Ryder Scott Reserves Conference, which covered a variety of reserves topics including analysis techniques for unconventional reservoirs, ESG and regulatory issues, reserves definitions and guidelines, SEC comment letter trends, and others. In addition, Mr. Gardner participated in various SPE and SPEE technical seminars, and other internal company training courses throughout the year, including one course in which he was the primary instructor, covering topics such as reserves evaluation methods and evaluation software, RTA/PTA, ethics, regulatory issues, greenhouse gas management, geothermal energy, and more.

Based on his educational background, professional training and more than 15 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Gardner has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

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

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

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

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

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

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

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

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

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

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

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made toTitle 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

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

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

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing

Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In

Shut-in Reserves are expected to be recovered from:

(1)completion intervals that are open at the time of the estimate but which have not yet started producing;

(2)wells which were shut-in for market conditions or pipeline connections; or

(3)wells not capable of production for mechanical reasons.

Behind-Pipe

Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when

drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

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

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

BKV CORPORATION

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold Interests

BKV ASSETS

SEC Parameters

As of

December 31, 2021

/s/ Stephen E. Gardner
Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

COLORADO LICENSED
STEPHEN E. GARDNER
44720
8/12/2024
PROFESSIONAL ENGINEER

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

August 7, 2024

BKV Corporation
1200 17th Street, Suite 1850
Denver, CO 80202

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold interests of BKV Corporation (BKV) referred to as the BKV Assets as of December 31, 2021. The subject properties are located in the state of Pennsylvania. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on December 13, 2021 and presented herein, was prepared for public disclosure by BKV in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties referred to as the BKV Assets evaluated by Ryder Scott account for a portion of BKV's total net proved reserves as of December 31, 2021. Based on information provided by BKV, the third party estimate conducted by Ryder Scott addresses approximately 11 percent of the total net proved reserves of BKV on a barrel of oil equivalent, BOE basis as of December 31, 2022. (Natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent.)

The estimated reserves and future net income amounts presented in this report, as of December 31, 2021 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, as required by the SEC regulations. Actual future prices may vary considerably from the prices that were used in this report. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

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SUITE 2800, 350 7TH AVENUE, S.W. CALGARY, ALBERTA T2P 3N9 TEL (403) 262-2799

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold Interests of
BKV Corporation
BKV Assets
As of December 31, 2021

	Proved							
	Developed						Total	
	Producing		Non-Producing[1]		Undeveloped		Proved	
Net Reserves								
Gas – MMcf		200,440		0		300,958		501,398
Income Data ($M)								
Future Gross Revenue	$	558,998	$	0	$	848,149	$	1,407,147
Deductions		333,748		518		497,081		831,347
Future Net Income (FNI)	$	225,250	$	(518)	$	351,068	$	575,800
Discounted FNI @ 10%	$	134,529	$	(474)	$	125,610	$	259,665

[1] Negative values for Future Net Income and Discounted FNI are due to abandonment liability.

All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of BKV. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes, but in the state of Pennsylvania, these taxes are zero. The deductions incorporate the normal direct costs of operating the wells, the Pennsylvania Impact Fee (presented herein as ad valorem taxes), development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Gas reserves account for 100 percent of the total future gross revenue from the proved reserves reported herein.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income ($M) As of December 31, 2021	
Discount Rate Percent	Total Proved	
8	$	295,171
12	$	230,879
15	$	196,806
20	$	156,160

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The negative values of future net income and discounted FNI shown in the proved developed non-producing category comprise shut-in wells with only an abandonment liability.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At BKV's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

BKV's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of reserves actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which BKV owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The reserves for the properties included herein were estimated by performance methods or analogy. All of the proved reserves attributable to producing wells and/or reservoirs were estimated by decline curve analysis, a performance method which utilized extrapolations of historical production and pressure data ending between June and September 2021, depending on the availability of data for a given case and in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

The reserves for the properties included herein attributable to the undeveloped status category were estimated by analogy. The data utilized from the analogues were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

BKV has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved, probable and possible production and income, we have relied upon data furnished by BKV with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, the Pennsylvania Impact Fee, development costs, development plans, certain abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, and base maps. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by BKV. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For the producing wells included herein, our forecasts of future production rates and decline trends are based on the historical performance data of each well.

The initial performance of analogous wells was used to estimate the anticipated initial production rates for those locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by BKV. Locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, well completions, and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period.

We furnished BKV with the above mentioned average prices in effect on December 31, 2021. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used for the geographic area included in the report.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees, and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by BKV. The differentials furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose.

In addition, the table below summarizes the net volume weighted benchmark price adjusted for differentials and referred to herein as the "average realized prices." The average realized price shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves by reserves category for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Price	Average Realized Price
North America	Gas	Henry Hub	$3.598/MMBTU	$2.81/Mcf

The effects of derivative instruments designated as price hedges of gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by BKV and are based on the operating expense reports of BKV and include only those costs directly applicable to the leases or wells. The operating costs furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by BKV and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose.

The estimated net cost of abandonment after salvage was included for properties where certain abandonment costs net of salvage were provided by BKV, and which they requested be included in our report. The estimates of the net abandonment costs furnished by BKV were accepted without independent verification. We have made no inspections to determine if any other abandonment, decommissioning, and /or restoration costs may be necessary, in addition to the costs provided by BKV and included herein.

The proved undeveloped reserves in this report have been incorporated herein in accordance with BKV's plans to develop these reserves as of December 31, 2021. The implementation of BKV's development plans as presented to us and incorporated herein is subject to the approval process adopted by BKV's management. As the result of our inquiries during the course of preparing this report, BKV has informed us that the development activities included herein have been subjected to and received the internal approvals required by BKV's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to BKV. BKV has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, BKV has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2021, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by BKV were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to BKV. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by BKV.

For filings made with the SEC under the 1933 securities Act, we have provided our written consent for the references to our name as well as to the references to our third party report in the registration statement on Form S-1 by BKV. Our consent for such use is included as a separate exhibit to the filings made with the SEC by BKV.

We have provided BKV with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by BKV and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

/s/ Stephen E. Gardner

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

SEG (DRO)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Stephen E. Gardner is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Gardner, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Gardner served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Gardner's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Mr. Gardner earned a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001 (summa cum laude). He is a licensed Professional Engineer in the States of Colorado and Texas. Mr. Gardner is a member of the Society of Petroleum Engineers and a former chairperson of the Society of Petroleum Evaluation Engineers for the Denver Chapter. He also currently serves on the latter organization's board of directors at the international level.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Gardner fulfills. As part of his 2020 continuing education hours, Mr. Gardner attended the annual Ryder Scott Reserves Conference, which covered a variety of reserves topics including analysis techniques for unconventional reservoirs, ESG and regulatory issues, reserves definitions and guidelines, SEC comment letter trends, and others. In addition, Mr. Gardner participated in various SPE and SPEE technical seminars, and other internal company training courses throughout the year, including one course in which he was the primary instructor, covering topics such as reserves evaluation methods and evaluation software, RTA/PTA, ethics, regulatory issues, greenhouse gas management, geothermal energy, and more.

Based on his educational background, professional training and more than 15 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Gardner has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): *Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).*

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

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

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

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

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

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

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

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

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

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

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

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

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

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

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing

Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In

Shut-in Reserves are expected to be recovered from:

(1)completion intervals that are open at the time of the estimate but which have not yet started producing;

(2)wells which were shut-in for market conditions or pipeline connections; or

(3)wells not capable of production for mechanical reasons.

Behind-Pipe

Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled,

unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

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

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

Exhibit 99.9

BKV CORPORATION

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

BARNETT ASSETS

SEC Parameters

As of

December 31, 2022

/s/ Stephen E. Gardner
Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

COLORADO LICENSED STEPHEN E. GARDNER 44720 8/12/2024 PROFESSIONAL ENGINEER

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPELS REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

August 7, 2024

BKV Corporation
1200 17th Street, Suite 1850
Denver, CO 80202

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of BKV Corporation (BKV) referred to as the Barnett Assets as of December 31, 2022. The subject properties are located in the state of Texas. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on December 17, 2022 and presented herein, was prepared for public disclosure by BKV in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties referred to as the Barnett Assets evaluated by Ryder Scott account for a portion of BKV's total net proved reserves as of December 31, 2022. Based on information provided by BKV, the third party estimate conducted by Ryder Scott addresses approximately 62 percent of the total net proved reserves of BKV on a barrel of oil equivalent, BOE basis as of December 31, 2022. (Natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent.)

The estimated reserves and future net income amounts presented in this report, as of December 31, 2022 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, as required by the SEC regulations. Actual future prices may vary considerably from the prices that were used in this report. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
BKV Corporation
Barnett Assets
As of December 31, 2022

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Reserves				
Oil/Condensate – Mbbl	932	0	698	1,630
Plant Products – Mbbl	140,272	11,757	36,575	188,604
Gas – MMcf	1,925,719	204,712	505,583	2,636,014
Income Data ($M)				
Future Gross Revenue	$ 14,872,705	$ 1,481,877	$ 4,089,392	$ 20,443,974
Deductions	5,222,342	486,733	1,645,107	7,354,182
Future Net Income (FNI)	$ 9,650,363	$ 995,144	$ 2,444,285	$ 13,089,792
Discounted FNI @ 10%	$ 4,228,165	$ 313,096	$ 817,995	$ 5,359,256

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (Mbbl). All gas volumes are expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas volumes are located. All gas reserves volumes are reported on an "as sold" basis. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of BKV. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Gas reserves account for approximately 73 percent and liquid hydrocarbon reserves account for the remaining 27 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income ($M) As of December 31, 2022
Discount Rate Percent	Total Proved
8	$ 6,099,770
12	$ 4,778,036
15	$ 4,109,598
20	$ 3,334,849

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The proved developed non-producing reserves included herein consist of the behind pipe status category.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At BKV's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

BKV's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of reserves actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which BKV owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The reserves for the properties included herein were estimated by performance methods or analogy. All of the proved reserves attributable to producing wells and/or reservoirs were estimated by decline curve analysis, a performance method which utilized extrapolations of historical production and pressure data ending between August and October 2022, depending on the availability of data for a given case and in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

The reserves for the properties included herein attributable to the non-producing and the undeveloped status categories were estimated by analogy. The data utilized from the analogues were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

To estimate economically producible proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

BKV has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by BKV with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, development costs, development plans, certain abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, and base maps. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by BKV. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For the producing wells included herein, our forecasts of future production rates and decline trends are based on the historical performance data of each well.

The initial performance of analogous wells was used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by BKV. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, well completions, and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period.

We furnished BKV with the above mentioned average benchmark prices in effect on December 31, 2022. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used for the geographic area included in the report.

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, certain gas firm transportation fees, certain NGL fractionation and transportation fees, and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by BKV. The differentials furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the "average realized prices." The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves by reserves category for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
	Oil/Condensate	WTI Cushing	$93.67/bbl	$86.92/bbl
United States	NGLs	WTI Cushing	$93.67/bbl	$30.10/bbl
	Gas	Henry Hub	$6.358/MMBTU	$6.03/Mcf

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by BKV and are based on the operating expense reports of BKV and include only those costs directly applicable to the leases or wells. Certain gas gathering and transportation costs were included as operating expenses. The operating costs furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by BKV and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness using information furnished by BKV for this purpose.

The estimated net cost of abandonment after salvage was included for properties where certain abandonment costs net of salvage were provided by BKV, and which they requested be included in our report. The estimates of the net abandonment costs furnished by BKV were accepted without independent verification. We have made no inspections to determine if any other abandonment, decommissioning, and /or restoration costs may be necessary, in addition to the costs provided by BKV and included herein.

The proved developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with BKV's plans to develop these reserves as of December 31, 2022. The implementation of BKV's development plans as presented to us and incorporated herein is subject to the approval process adopted by BKV's management. As the result of our inquiries during the course of preparing this report, BKV has informed us that the development activities included herein have been subjected to and received the internal approvals required by BKV's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to BKV. BKV has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, BKV has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2022, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by BKV were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists receive professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to BKV. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by BKV.

For filings made with the SEC under the 1933 securities Act, we have provided our written consent for the references to our name as well as to the references to our third party report in the registration statement on Form S-1 by BKV. Our consent for such use is included as a separate exhibit to the filings made with the SEC by BKV.

We have provided BKV with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by BKV and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.

TBPELS Firm Registration No. F-1580

/s/ Stephen E. Gardner

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

SEG (DRO)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Stephen E. Gardner is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Gardner, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Gardner served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Gardner's geographic and job specific experience, please refer to the Ryder Scott Company website at https://ryderscott.com/employees/denver-employees.

Mr. Gardner earned a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001 (summa cum laude). He is a licensed Professional Engineer in the States of Colorado and Texas. Mr. Gardner is a member of the Society of Petroleum Engineers and a former chairperson of the Society of Petroleum Evaluation Engineers for the Denver Chapter. He also currently serves on the latter organization's board of directors at the international level.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Gardner fulfills. As part of his 2021 continuing education hours, Mr. Gardner attended the annual Ryder Scott Reserves Conference, which covered a variety of reserves topics including analysis techniques for unconventional reservoirs, ESG issues, reserves definitions and guidelines, SEC comment letter trends, and others. In addition, Mr. Gardner participated in various SPE and SPEE technical seminars, and other internal company training courses throughout the year covering topics such as reserves evaluation methods and evaluation software, ethics, regulatory issues, greenhouse gas management, and more.

Based on his educational background, professional training and more than 16 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Gardner has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): *Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).*

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

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

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

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

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

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

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

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

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

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

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

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

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

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

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing

Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In

Shut-in Reserves are expected to be recovered from:

(1)completion intervals that are open at the time of the estimate but which have not yet started producing;

(2)wells which were shut-in for market conditions or pipeline connections; or

(3)wells not capable of production for mechanical reasons.

Behind-Pipe

Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

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

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

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

Exhibit 99.10

BKV CORPORATION

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold Interests

CHAFFEE CORNERS ASSETS

SEC Parameters

As of

December 31, 2022

/s/ Stephen E. Gardner
Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

August 7, 2024

BKV Corporation
1200 17th Street, Suite 1850
Denver, CO 80202

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold interests of BKV Corporation (BKV) referred to as the Chaffee Corners Assets as of December 31, 2022. The subject properties are located in the state of Pennsylvania. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on December 17, 2022 and presented herein, was prepared for public disclosure by BKV in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties referred to as the Chaffee Corners Assets evaluated by Ryder Scott account for a portion of BKV's total net proved reserves as of December 31, 2022. Based on information provided by BKV, the third party estimate conducted by Ryder Scott addresses approximately 1 percent of the total net proved reserves of BKV on a barrel of oil equivalent, BOE basis as of December 31, 2022. (Natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent.)

The estimated reserves and future net income amounts presented in this report, as of December 31, 2022 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, as required by the SEC regulations. Actual future prices may vary considerably from the prices that were used in this report. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold Interests of
BKV Corporation
Chaffee Corners Assets
As of December 31, 2022

	Proved							
	Developed						Total	
	Producing		Non-Producing[1]		Undeveloped		Proved	
Net Reserves								
Gas – MMcf		72,789		0		12,695		85,484
Income Data ($M)								
Future Gross Revenue	$	449,685	$	0	$	78,429	$	528,114
Deductions		71,706		68		14,341		86,115
Future Net Income (FNI)	$	377,979	$	(68)	$	64,088	$	441,999
Discounted FNI @ 10%	$	174,030	$	(62)	$	28,971	$	202,939

(1) Negative values for Future Net Income and Discounted FNI are due to abandonment liability.

All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of BKV. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes, but in the state of Pennsylvania, these taxes are zero. The deductions incorporate the normal direct costs of operating the wells, the Pennsylvania Impact Fee (presented herein as ad valorem taxes), development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Gas reserves account for 100 percent of the total future gross revenue from the proved reserves reported herein.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income ($M) As of December 31, 2022	
Discount Rate Percent	Total Proved	
8	$	226,896
12	$	183,927
15	$	161,792
20	$	135,670

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission’s Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled “PETROLEUM RESERVES DEFINITIONS” is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled “PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES” in this report. The negative values of future net income and discounted FNI shown in the proved developed non-producing category comprise shut-in wells with only an abandonment liability.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are “estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At BKV's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

BKV's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of reserves actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which BKV owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The reserves for the properties included herein were estimated by performance methods or analogy. All of the proved reserves attributable to producing wells and/or reservoirs were estimated by decline curve analysis, a performance method which utilized extrapolations of historical production and pressure data ending between August and October 2022, depending on the availability of data for a given case and in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

The reserves for the properties included herein attributable to the undeveloped status category were estimated by analogy. The data utilized from the analogues were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

To estimate economically producible proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

BKV has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by BKV with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, the Pennsylvania Impact Fee, development costs, development plans, certain abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, and base maps. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by BKV. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For the producing wells included herein, our forecasts of future production rates and decline trends are based on the historical performance data of each well.

The initial performance of analogous wells was used to estimate the anticipated initial production rates for those locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by BKV. Locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, well completions, and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period.

We furnished BKV with the above mentioned average benchmark price in effect on December 31, 2022. The initial SEC hydrocarbon price was determined using the 12-month average first-day-of-the-month benchmark price appropriate to the geographic area where the hydrocarbons are sold. The benchmark price is prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark price" and "price reference" used for the geographic area included in the report.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark price for gravity, quality, local conditions, and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by BKV. The differentials furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose.

In addition, the table below summarizes the net volume weighted benchmark price adjusted for differentials and referred to herein as the "average realized prices." The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves by reserves category for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Price	Average Realized Price
North America	Gas	Henry Hub	$6.358/MMBTU	$6.18/Mcf

The effects of derivative instruments designated as price hedges of gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by BKV and are based on the operating expense reports of BKV and include only those costs directly applicable to the leases or wells. Certain gathering and transportation fees are included as operating costs. The operating costs furnished by BKV were reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by BKV to determine these costs. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by BKV and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by BKV were reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by BKV to determine these costs.

The estimated net cost of abandonment after salvage was included for properties where certain abandonment costs net of salvage were provided by BKV, and which they requested be included in our report. The estimates of the net abandonment costs furnished by BKV were accepted without independent verification. We have made no inspections to determine if any other abandonment, decommissioning, and /or restoration costs may be necessary, in addition to the costs provided by BKV and included herein.

The proved undeveloped reserves in this report have been incorporated herein in accordance with BKV's plans to develop these reserves as of December 31, 2022. The implementation of BKV's development plans as presented to us and incorporated herein is subject to the approval process adopted by BKV's management. As the result of our inquiries during the course of preparing this report, BKV has informed us that the development activities included herein have been subjected to and received the internal approvals required by BKV's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to BKV. BKV has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, BKV has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2022, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by BKV were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists receive professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to BKV. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by BKV.

For filings made with the SEC under the 1933 securities Act, we have provided our written consent for the references to our name as well as to the references to our third party report in the registration statement on Form S-1 by BKV. Our consent for such use is included as a separate exhibit to the filings made with the SEC by BKV.

We have provided BKV with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by BKV and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

/s/ Stephen E. Gardner
Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

SEG (DRO)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Stephen E. Gardner is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Gardner, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Gardner served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Gardner's geographic and job specific experience, please refer to the Ryder Scott Company website at https://ryderscott.com/employees/denver-employees.

Mr. Gardner earned a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001 (summa cum laude). He is a licensed Professional Engineer in the States of Colorado and Texas. Mr. Gardner is a member of the Society of Petroleum Engineers and a former chairperson of the Society of Petroleum Evaluation Engineers for the Denver Chapter. He also currently serves on the latter organization's board of directors at the international level.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Gardner fulfills. As part of his 2021 continuing education hours, Mr. Gardner attended the annual Ryder Scott Reserves Conference, which covered a variety of reserves topics including analysis techniques for unconventional reservoirs, ESG issues, reserves definitions and guidelines, SEC comment letter trends, and others. In addition, Mr. Gardner participated in various SPE and SPEE technical seminars, and other internal company training courses throughout the year covering topics such as reserves evaluation methods and evaluation software, ethics, regulatory issues, greenhouse gas management, and more.

Based on his educational background, professional training and more than 16 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Gardner has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

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

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

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

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

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

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

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

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

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

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

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

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

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

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing

Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In

Shut-in Reserves are expected to be recovered from:

(1)completion intervals that are open at the time of the estimate but which have not yet started producing;

(2)wells which were shut-in for market conditions or pipeline connections; or

(3)wells not capable of production for mechanical reasons.

Behind-Pipe

Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

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

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

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

Exhibit 99.11

BKV CORPORATION

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

CHELSEA ASSETS

SEC Parameters

As of

December 31, 2022

/s/ Stephen E. Gardner

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

COLORADO LICENSED STEPHEN E. GARDNER S.E.G. 44720 8/12/2024 PROFESSIONAL ENGINEER

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

August 7, 2024

BKV Corporation
1200 17th Street, Suite 1850
Denver, CO 80202

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of BKV Corporation (BKV) referred to as the Chelsea Assets as of December 31, 2022. The subject properties are located in the state of Pennsylvania. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on December 17, 2022 and presented herein, was prepared for public disclosure by BKV in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties referred to as the Chelsea Assets evaluated by Ryder Scott account for a portion of BKV's total net proved reserves as of December 31, 2022. Based on information provided by BKV, the third party estimate conducted by Ryder Scott addresses approximately 6 percent of the total net proved reserves of BKV on a barrel of oil equivalent, BOE basis as of December 31, 2022. (Natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent.)

The estimated reserves and future net income amounts presented in this report, as of December 31, 2022 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, as required by the SEC regulations. Actual future prices may vary considerably from the prices that were used in this report. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
BKV Corporation
Chelsea Assets
As of December 31, 2022

	Proved			
	Developed			Total
	Producing	Non-Producing[1]	Undeveloped	Proved
Net Reserves				
Gas – MMcf	209,818	0	143,054	352,872
Income Data ($M)				
Future Gross Revenue	$ 1,182,519	$ 0	$ 808,029	$ 1,990,548
Deductions	357,599	376	264,370	622,345
Future Net Income (FNI)	$ 824,920	$ (376)	$ 543,659	$ 1,368,203
Discounted FNI @ 10%	$ 403,882	$ (345)	$ 220,551	$ 624,088

(1) Negative values for Future Net Income and Discounted FNI are due to abandonment liability.

All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of BKV. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes, but in the state of Pennsylvania, these taxes are zero. The deductions incorporate the normal direct costs of operating the wells, the Pennsylvania Impact Fee (presented herein as ad valorem taxes), development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Gas reserves account for 100 percent of the total future gross revenue from the proved reserves reported herein.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income ($M) As of December 31, 2022
Discount Rate Percent	Total Proved
8	$ 701,737
12	$ 561,862
15	$ 488,768
20	$ 401,763

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The negative values of future net income and discounted FNI shown in the proved developed non-producing category comprise shut-in wells with only an abandonment liability.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At BKV's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

BKV's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of reserves actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which BKV owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The reserves for the properties included herein were estimated by performance methods or analogy. All of the proved reserves attributable to producing wells and/or reservoirs were estimated by decline curve analysis, a performance method which utilized extrapolations of historical production and pressure data ending between August and October 2022, depending on the availability of data for a given case and in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

The reserves for the properties included herein attributable to the undeveloped status category were estimated by analogy. The data utilized from the analogues were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

To estimate economically producible proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

BKV has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by BKV with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, the Pennsylvania Impact Fee, development costs, development plans, certain abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, and base maps. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by BKV. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For the producing wells included herein, our forecasts of future production rates and decline trends are based on the historical performance data of each well.

The initial performance of analogous wells was used to estimate the anticipated initial production rates for those locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by BKV. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, well completions, and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period.

We furnished BKV with the above mentioned average benchmark price in effect on December 31, 2022. The initial SEC hydrocarbon price was determined using the 12-month average first-day-of-the-month benchmark price appropriate to the geographic area where the hydrocarbons are sold. The benchmark price is prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark price” and “price reference” used for the geographic area included in the report.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark price for gravity, quality, local conditions, and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by BKV. The differentials furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose.

In addition, the table below summarizes the net volume weighted benchmark price adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves by reserves category for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Price	Average Realized Price
North America	Gas	Henry Hub	$6.358/MMBTU	$5.64/Mcf

The effects of derivative instruments designated as price hedges of gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by BKV and are based on the operating expense reports of BKV and include only those costs directly applicable to the leases or wells. Certain gathering and transportation fees are included as operating costs. The operating costs furnished by BKV were reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by BKV to determine these costs. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by BKV and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by BKV were reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by BKV to determine these costs.

The estimated net cost of abandonment after salvage was included for properties where certain abandonment costs net of salvage were provided by BKV, and which they requested be included in our report. The estimates of the net abandonment costs furnished by BKV were accepted without independent verification. We have made no inspections to determine if any other abandonment, decommissioning, and /or restoration costs may be necessary, in addition to the costs provided by BKV and included herein.

The proved undeveloped reserves in this report have been incorporated herein in accordance with BKV's plans to develop these reserves as of December 31, 2022. The implementation of BKV's development plans as presented to us and incorporated herein is subject to the approval process adopted by BKV's management. As the result of our inquiries during the course of preparing this report, BKV has informed us that the development activities included herein have been subjected to and received the internal approvals required by BKV's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to BKV. BKV has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, BKV has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2022, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by BKV were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists receive professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to BKV. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by BKV.

For filings made with the SEC under the 1933 securities Act, we have provided our written consent for the references to our name as well as to the references to our third party report in the registration statement on Form S-1 by BKV. Our consent for such use is included as a separate exhibit to the filings made with the SEC by BKV.

We have provided BKV with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by BKV and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

/s/ Stephen E. Gardner
Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

SEG (DRO)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Stephen E. Gardner is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Gardner, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Gardner served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Gardner's geographic and job specific experience, please refer to the Ryder Scott Company website at https://ryderscott.com/employees/denver-employees.

Mr. Gardner earned a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001 (summa cum laude). He is a licensed Professional Engineer in the States of Colorado and Texas. Mr. Gardner is a member of the Society of Petroleum Engineers and a former chairperson of the Society of Petroleum Evaluation Engineers for the Denver Chapter. He also currently serves on the latter organization's board of directors at the international level.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Gardner fulfills. As part of his 2021 continuing education hours, Mr. Gardner attended the annual Ryder Scott Reserves Conference, which covered a variety of reserves topics including analysis techniques for unconventional reservoirs, ESG issues, reserves definitions and guidelines, SEC comment letter trends, and others. In addition, Mr. Gardner participated in various SPE and SPEE technical seminars, and other internal company training courses throughout the year covering topics such as reserves evaluation methods and evaluation software, ethics, regulatory issues, greenhouse gas management, and more.

Based on his educational background, professional training and more than 16 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Gardner has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal

methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

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

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

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

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

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

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

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

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

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

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

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

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

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

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing

Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In

Shut-in Reserves are expected to be recovered from:

(1)completion intervals that are open at the time of the estimate but which have not yet started producing;

(2)wells which were shut-in for market conditions or pipeline connections; or

(3)wells not capable of production for mechanical reasons.

Behind-Pipe

Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

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

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

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

Exhibit 99.12

BKV CORPORATION

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

BKV ASSETS

SEC Parameters

As of

December 31, 2022

/s/ Stephen E. Gardner
Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

August 7, 2024

BKV Corporation
1200 17th Street, Suite 1850
Denver, CO 80202

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of BKV Corporation (BKV) referred to as the BKV Assets as of December 31, 2022. The subject properties are located in the state of Pennsylvania. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on December 17, 2022 and presented herein, was prepared for public disclosure by BKV in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties referred to as the BKV Assets evaluated by Ryder Scott account for a portion of BKV's total net proved reserves as of December 31, 2022. Based on information provided by BKV, the third party estimate conducted by Ryder Scott addresses approximately 7 percent of the total net proved reserves of BKV on a barrel of oil equivalent, BOE basis as of December 31, 2022. (Natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent.)

The estimated reserves and future net income amounts presented in this report, as of December 31, 2022 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, as required by the SEC regulations. Actual future prices may vary considerably from the prices that were used in this report. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
BKV Corporation
BKV Assets
As of December 31, 2022

	Proved			
	Developed			Total
	Producing	Non-Producing[1]	Undeveloped	Proved
Net Reserves				
Gas – MMcf	266,438	0	195,552	461,990
Income Data ($M)				
Future Gross Revenue	$ 1,510,469	$ 0	$ 1,110,932	$ 2,621,401
Deductions	448,419	673	392,813	841,905
Future Net Income (FNI)	$ 1,062,050	$ (673)	$ 718,119	$ 1,779,496
Discounted FNI @ 10%	$ 542,822	$ (616)	$ 291,168	$ 833,374

(1) Negative values for Future Net Income and Discounted FNI are due to abandonment liability.

All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of BKV. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes, but in the state of Pennsylvania, these taxes are zero. The deductions incorporate the normal direct costs of operating the wells, the Pennsylvania Impact Fee (presented herein as ad valorem taxes), development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Gas reserves account for 100 percent of the total future gross revenue from the proved reserves reported herein.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

Discount Rate Percent	Discounted Future Net Income ($M) As of December 31, 2022 Total Proved
8	$ 932,534
12	$ 753,705
15	$ 659,827
20	$ 547,565

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The negative values of future net income and discounted FNI shown in the proved developed non-producing category comprise shut-in wells with only an abandonment liability.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved, probable and possible gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At BKV's request, this report addresses the only proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

BKV's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of reserves actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which BKV owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The reserves for the properties included herein were estimated by performance methods or analogy. All of the proved reserves attributable to producing wells and/or reservoirs were estimated by decline curve analysis, a performance method which utilized extrapolations of historical production and pressure data ending between August and October 2022, depending on the availability of data for a given case and in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

The reserves for the properties included herein attributable to the undeveloped status category were estimated by analogy. The data utilized from the analogues were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

To estimate economically producible proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

BKV has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by BKV with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, the Pennsylvania Impact Fee, development costs, development plans, certain abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, and base maps. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by BKV. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved, probable and possible reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For the producing wells included herein, our forecasts of future production rates and decline trends are based on the historical performance data of each well.

The initial performance of analogous wells was used to estimate the anticipated initial production rates for those locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by BKV. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, well completions, and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period.

We furnished BKV with the above mentioned average benchmark price in effect on December 31, 2022. The initial SEC hydrocarbon price was determined using the 12-month average first-day-of-the-month benchmark price appropriate to the geographic area where the hydrocarbons are sold. The benchmark price is prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark price” and “price reference” used for the geographic area included in the report.

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark price for gravity, quality, local conditions, and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by BKV. The differentials furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose.

In addition, the table below summarizes the net volume weighted benchmark price adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves by reserves category for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Price	Average Realized Price
North America	Gas	Henry Hub	$6.358/MMBTU	$5.67/Mcf

The effects of derivative instruments designated as price hedges of gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by BKV and are based on the operating expense reports of BKV and include only those costs directly applicable to the leases or wells. Certain gathering and transportation fees are included as operating costs. The operating costs furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by BKV and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose.

The estimated net cost of abandonment after salvage was included for properties where certain abandonment costs net of salvage were provided by BKV, and which they requested be included in our report. The estimates of the net abandonment costs furnished by BKV were accepted without independent verification. We have made no inspections to determine if any other abandonment, decommissioning, and /or restoration costs may be necessary, in addition to the costs provided by BKV and included herein.

The proved undeveloped reserves in this report have been incorporated herein in accordance with BKV's plans to develop these reserves as of December 31, 2022. The implementation of BKV's development plans as presented to us and incorporated herein is subject to the approval process adopted by BKV's management. As the result of our inquiries during the course of preparing this report, BKV has informed us that the development activities included herein have been subjected to and received the internal approvals required by BKV's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to BKV. BKV has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, BKV has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2022, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by BKV were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists receive professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to BKV. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by BKV.

For filings made with the SEC under the 1933 securities Act, we have provided our written consent for the references to our name as well as to the references to our third party report in the registration statement on Form S-1 by BKV. Our consent for such use is included as a separate exhibit to the filings made with the SEC by BKV.

We have provided BKV with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by BKV and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

/s/ Stephen E. Gardner
Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

SEG (DRO)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Stephen E. Gardner is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Gardner, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Gardner served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Gardner's geographic and job specific experience, please refer to the Ryder Scott Company website at https://ryderscott.com/employees/denver-employees.

Mr. Gardner earned a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001 (summa cum laude). He is a licensed Professional Engineer in the States of Colorado and Texas. Mr. Gardner is a member of the Society of Petroleum Engineers and a former chairperson of the Society of Petroleum Evaluation Engineers for the Denver Chapter. He also currently serves on the latter organization's board of directors at the international level.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Gardner fulfills. As part of his 2021 continuing education hours, Mr. Gardner attended the annual Ryder Scott Reserves Conference, which covered a variety of reserves topics including analysis techniques for unconventional reservoirs, ESG issues, reserves definitions and guidelines, SEC comment letter trends, and others. In addition, Mr. Gardner participated in various SPE and SPEE technical seminars, and other internal company training courses throughout the year covering topics such as reserves evaluation methods and evaluation software, ethics, regulatory issues, greenhouse gas management, and more.

Based on his educational background, professional training and more than 16 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Gardner has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal

methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): *Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (*i.e.*, absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (*i.e.*, potentially recoverable resources from undiscovered accumulations).*

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

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

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

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

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

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

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

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

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

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

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

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

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

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

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing

Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In

Shut-in Reserves are expected to be recovered from:

(1)completion intervals that are open at the time of the estimate but which have not yet started producing;

(2)wells which were shut-in for market conditions or pipeline connections; or

(3)wells not capable of production for mechanical reasons.

Behind-Pipe

Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

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

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

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

Exhibit 99.13

BKV CORPORATION

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

NORTH TEXAS ASSETS

SEC Parameters

As of

December 31, 2022

/s/ Stephen E. Gardner
Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

August 7, 2024

BKV Corporation
1200 17th Street, Suite 1850
Denver, CO 80202

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production and income attributable to certain leasehold and royalty interests of BKV Corporation (BKV) referred to as the North Texas Assets as of December 31, 2022. The subject properties are located in the state of Texas. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on December 17, 2022 and presented herein, was prepared for public disclosure by BKV in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties referred to as the North Texas Assets evaluated by Ryder Scott account for a portion of BKV's total net proved reserves as of December 31, 2022. Based on information provided by BKV, the third party estimate conducted by Ryder Scott addresses approximately 24 percent of the total net proved reserves of BKV on a barrel of oil equivalent, BOE basis as of December 31, 2022. (Natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent.)

The estimated reserves and future net income amounts presented in this report, as of December 31, 2022 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, as required by the SEC regulations. Actual future prices may vary considerably from the prices that were used in this report. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests
BKV Corporation
North Texas Assets
As of December 31, 2022

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Reserves				
Oil/Condensate – Mbbl	179	0	60	239
Plant Products – Mbbl	17,313	1,498	4,085	22,896
Gas – MMcf	994,132	124,411	200,773	1,319,316
Income Data ($M)				
Future Gross Revenue	$ 5,797,831	$ 700,063	$ 1,162,341	$ 7,660,235
Deductions	2,423,881	255,181	495,118	3,174,180
Future Net Income (FNI)	$ 3,373,950	$ 444,882	$ 667,223	$ 4,486,055
Discounted FNI @ 10%	$ 1,602,617	$ 125,401	$ 206,827	$ 1,934,845

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (Mbbl). All gas volumes are expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas volumes are located. All gas reserves volumes are reported on an "as sold" basis. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of BKV. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, recompletion and development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Gas reserves account for approximately 92 percent and liquid hydrocarbon reserves account for the remaining 8 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

Discount Rate Percent	Discounted Future Net Income ($M) As of December 31, 2022 Total Proved
8	$ 2,192,350
12	$ 1,730,861
15	$ 1,494,471
20	$ 1,218,578

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS and GUIDELINES" in this report. The proved developed non-producing reserves included herein consist of the behind pipe status category.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At BKV's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

BKV's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of reserves actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which BKV owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The reserves for the properties included herein were estimated by performance methods or analogy. All of the proved reserves attributable to producing wells and/or reservoirs were estimated by decline curve analysis, a performance method which utilized extrapolations of historical production and pressure data ending between August and October 2022, depending on the availability of data for a given case and in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

The reserves for the properties included herein attributable to the non-producing and the undeveloped status categories were estimated by analogy. The data utilized from the analogues were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

To estimate economically producible proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

BKV has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by BKV with respect to property interests acquired, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, development plans, certain abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, and base maps. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by BKV. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For the producing wells included herein, our forecasts of future production rates and decline trends are based on the historical performance data of each well.

The initial performance of analogous wells was used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by BKV. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, well completions, and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period.

We furnished BKV with the above mentioned average benchmark prices in effect on December 31, 2022. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used for the geographic area included in the report.

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by BKV. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by BKV to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the "average realized prices." The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves by reserves category for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
	Oil/Condensate	WTI Cushing	$93.67/bbl	$88.12/bbl

United States	NGLs	WTI Cushing	$93.67/bbl	$29.05/bbl
	Gas	Henry Hub	$6.358/MMBTU	$5.65/Mcf

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by BKV and are based on the operating expense reports of BKV and include only those costs directly applicable to the leases or wells. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by BKV. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by BKV and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose.

The estimated net cost of abandonment after salvage was included for properties where certain abandonment costs net of salvage were provided by BKV, and which they requested be included in our report. The estimates of the net abandonment costs furnished by BKV were accepted without independent verification. We have made no inspections to determine if any other abandonment, decommissioning, and /or restoration costs may be necessary, in addition to the costs provided by BKV and included herein.

The proved developed non-producing and proved undeveloped reserves in this report have been incorporated herein in accordance with BKV's plans to develop these reserves as of December 31, 2022. The implementation of BKV's development plans as presented to us and incorporated herein is subject to the approval process adopted by BKV's management. As the result of our inquiries during the course of preparing this report, BKV has informed us that the development activities included herein have been subjected to and received the internal approvals required by BKV's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to BKV. BKV has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, BKV has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2022, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by BKV were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists receive professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to BKV. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by BKV.

For filings made with the SEC under the 1933 securities Act, we have provided our written consent for the references to our name as well as to the references to our third party report in the registration statement on Form S-1 by BKV. Our consent for such use is included as a separate exhibit to the filings made with the SEC by BKV.

We have provided BKV with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by BKV and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

/s/ Stephen E. Gardner
Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

SEG (DRO)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Stephen E. Gardner is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Gardner, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Gardner served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Gardner's geographic and job specific experience, please refer to the Ryder Scott Company website at https://ryderscott.com/employees/denver-employees.

Mr. Gardner earned a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001 (summa cum laude). He is a licensed Professional Engineer in the States of Colorado and Texas. Mr. Gardner is a member of the Society of Petroleum Engineers and a former chairperson of the Society of Petroleum Evaluation Engineers for the Denver Chapter. He also currently serves on the latter organization's board of directors at the international level.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Gardner fulfills. As part of his 2021 continuing education hours, Mr. Gardner attended the annual Ryder Scott Reserves Conference, which covered a variety of reserves topics including analysis techniques for unconventional reservoirs, ESG issues, reserves definitions and guidelines, SEC comment letter trends, and others. In addition, Mr. Gardner participated in various SPE and SPEE technical seminars, and other internal company training courses throughout the year covering topics such as reserves evaluation methods and evaluation software, ethics, regulatory issues, greenhouse gas management, and more.

Based on his educational background, professional training and more than 16 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Gardner has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

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

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

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

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

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

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

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

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

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

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

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

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

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

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing

Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In

Shut-in Reserves are expected to be recovered from:
(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

Behind-Pipe

Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

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

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

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

Exhibit 99.14

BKV CORPORATION

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

SEC Parameters

As of

December 31, 2023

/s/ Stephen E. Gardner
Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

August 7, 2024

BKV Corporation
1200 17th Street, Suite 1850
Denver, CO 80202

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of BKV Corporation (BKV) as of December 31, 2023. The subject properties are located in the states of Pennsylvania and Texas. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on December 19, 2023 and presented herein, was prepared for public disclosure by BKV in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott account for 100 percent of BKV’s total net proved liquid hydrocarbon and gas reserves as of December 31, 2023.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2023 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

1100 LOUISIANA, SUITE 4600 HOUSTON, TEXAS 77002-5294 TEL (713) 651-9191
SUITE 2800, 350 7TH AVENUE, S.W. CALGARY, ALBERTA T2P 3N9 TEL (403) 262-2799

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
BKV Corporation
As of December 31, 2023

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Reserves				
Oil/Condensate – Mbbl	802	190	59	1,051
Plant Products – Mbbl	129,260	27,139	27,766	184,165
Gas – MMcf	2,290,025	153,047	539,423	2,982,495
MMCFE	3,070,397	317,021	706,373	4,093,791
Income Data ($M)				
Future Gross Revenue	$ 6,899,019	$ 804,693	$ 1,611,903	$ 9,315,615
Deductions	4,840,400	454,463	1,106,237	6,401,100
Future Net Income (FNI)	$ 2,058,619	$ 350,230	$ 505,666	$ 2,914,515
Discounted FNI @ 10%	$ 1,085,102	$ 66,139	$ 81,308	$ 1,232,549

PERCENTAGE OF PROVED RESERVES PER HYDROCARBON PHASE

OPERATED	**December 31, 2023**					
	Estimated		**%**		**Average Annual**	
	Total Proved	**%**	**Natural**		**PDP Decline**	
	Reserves	**Natural**	**Gas**	**%**	**Five**	**Ten**
Operating Region	**(MMCFE)**	**Gas**	**Liquids**	**Oil**	**Year**	**Year**
Barnett	3,620,862	69.6%	30.2%	0.2%	8%	7%
NEPA	272,855	100.0%	0.0%	0.0%	11%	10%
Total	3,893,717	71.7%	28.1%	0.2%	8%	8%

NON OPERATED	**December 31, 2023**					
	Estimated		**%**		**Average Annual**	
	Total Proved	**%**	**Natural**		**PDP Decline**	
	Reserves	**Natural**	**Gas**	**%**	**Five**	**Ten**
Operating Region	**(MMCFE)**	**Gas**	**Liquids**	**Oil**	**Year**	**Year**
Barnett	48,302	77.5%	22.1%	0.4%	10%	9%
NEPA	151,772	100.0%	0.0%	0.0%	9%	8%
Total	200,074	94.6%	5.3%	0.1%	9%	8%

TOTAL COMPANY	**December 31, 2023**					
	Estimated		**%**		**Average Annual**	
	Total Proved	**%**	**Natural**		**PDP Decline**	
	Reserves	**Natural**	**Gas**	**%**	**Five**	**Ten**
Operating Region	**(MMCFE)**	**Gas**	**Liquids**	**Oil**	**Year**	**Year**
Barnett	3,669,164	69.7%	30.1%	0.2%	8%	7%
NEPA	424,627	100.0%	0.0%	0.0%	11%	9%
Total	4,093,791	72.8%	27.0%	0.2%	8%	8%

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (Mbbl). All gas volumes are expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas volumes are located. All gas reserves volumes are reported on an "as sold" basis. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M). The net reserves volumes are also shown herein on an equivalent unit basis wherein hydrocarbon liquid is converted to natural gas equivalent using a factor of 1 barrel of liquid per 6,000 cubic feet of natural gas equivalent. MMCFE means million cubic feet of natural gas equivalent.

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software packageARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of BKV. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes (including the Pennsylvania Impact Fee), development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Gas reserves account for approximately 64 percent and liquid hydrocarbon reserves account for the remaining 36 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates, which were also compounded monthly. These results are shown in summary form as follows.

		Discounted Future Net Income ($M) As of December 31, 2023
Discount Rate Percent		Total Proved
8	$	1,409,977
12	$	1,090,539
15	$	924,494
20	$	729,281

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The proved developed non-producing reserves included herein consist of the behind pipe status category.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At BKV's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

BKV's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of reserves actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which BKV owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods, which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The reserves for the properties included herein were estimated by performance methods or analogy. In general, the proved reserves attributable to producing wells and/or reservoirs were estimated by decline curve analysis, a performance method which utilized extrapolations of historical production and pressure data ending between August and October 2023, depending on the availability of data for a given case and in those cases where such data were considered to be definitive. For certain early-life cases, where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the estimates was considered to be inappropriate, producing reserves were estimated by analogy. The data utilized in our analysis were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

The reserves for the properties included herein attributable to the non-producing and the undeveloped status categories were estimated by analogy. The data utilized from the analogues were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

To estimate economically producible proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

BKV has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by BKV with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem taxes (including the Pennsylvania Impact Fee), production taxes, development costs, development plans, certain abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structure and isochore maps, and base maps. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by BKV. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For the producing wells included herein, our forecasts of future production rates and decline trends are based on the historical performance data of each well. If no production decline trend has been established, future decline trends were based on analogy to older, more established wells.

The initial performance of analogous wells was used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by BKV. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, well completions, and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period.

We furnished BKV with the above mentioned average benchmark prices in effect on December 31, 2023. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark prices" and "price reference" used for the geographic area included in the report.

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, certain gas firm transportation fees, certain NGL fractionation and transportation fees, and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by BKV. The differentials furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the "average realized prices." The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves by reserves category for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	WTI Cushing	$78.22/bbl	$70.80/bbl
	NGLs	WTI Cushing	$78.22/bbl	$18.40/bbl
	Gas	Henry Hub	$2.637/MMBTU	$2.09/Mcf

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by BKV and are based on the operating expense reports of BKV and include only those costs directly applicable to the leases or wells. Certain gas gathering and transportation costs were included as operating expenses. The operating costs furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by BKV and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness using information furnished by BKV for this purpose.

The estimated net cost of abandonment after salvage was included for properties where certain abandonment costs net of salvage were provided by BKV, and which they requested be included in our report. The estimates of the net abandonment costs furnished by BKV were accepted without independent verification. We have made no inspections to determine if any other abandonment, decommissioning, and /or restoration costs may be necessary, in addition to the costs provided by BKV and included herein.

The proved developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with BKV's plans to develop these reserves as of December 31, 2023. The implementation of BKV's development plans as presented to us and incorporated herein is subject to the approval process adopted by BKV's management. As the result of our inquiries during the course of preparing this report, BKV has informed us that the development activities included herein have been subjected to and received the internal approvals required by BKV's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to BKV. BKV has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, BKV has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2023, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by BKV were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists receive professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to BKV. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott.The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by BKV.

For filings made with the SEC under the 1933 securities Act, we have provided our written consent for the references to our name as well as to the references to our third party report in the registration statement on Form S-1 by BKV. Our consent for such use is included as a separate exhibit to the filings made with the SEC by BKV.

We have provided BKV with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by BKV and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

/s/ Stephen E. Gardner

Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

SEG (GR)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Stephen E. Gardner is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Gardner, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for ongoing reservoir evaluation studies worldwide, as well as for coordinating and supervising the evaluations of staff and consulting engineers of the company. Mr. Gardner is also a member of Ryder Scott's Board of Directors. Before joining Ryder Scott, Mr. Gardner served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Gardner's geographic and job specific experience, please refer to the Ryder Scott Company website at https://ryderscott.com/employees/denver-employees.

Mr. Gardner earned a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001 (summa cum laude). He is a licensed Professional Engineer in the States of Colorado and Texas. Mr. Gardner is a member of the Society of Petroleum Engineers (SPE) and a former director of the Society of Petroleum Evaluation Engineers (SPEE). He currently serves as an officer for SPEE at the international level.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Gardner fulfills. As part of his 2023 continuing education hours, Mr. Gardner attended multiple technical conferences, which covered a variety of reserves topics including analysis techniques for unconventional reservoirs, ESG issues, reserves definitions and guidelines, SEC comment letter trends, and others. Mr. Gardner was a featured speaker for geothermal resource evaluation and classification at an SPE technical workshop in August 2023. In addition, Mr. Gardner participated in various local technical seminars and other internal company training courses throughout the year covering topics such as reserves evaluation methods and evaluation software, ethics, M&A trends, regulatory issues, geothermal energy, SRMS, and more.

Based on his educational background, professional training and more than 18 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Gardner has attained the professional qualifications as a Reserves Estimator set forth in Article III of the “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information” promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the “Modernization of Oil and Gas Reporting; Final Rule” in the Federal Register of National Archives and Records Administration (NARA). The “Modernization of Oil and Gas Reporting; Final Rule” includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The “Modernization of Oil and Gas Reporting; Final Rule”, including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the “SEC regulations”. The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

<u>RESERVES (SEC DEFINITIONS)</u>

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

<u>Note to paragraph (a)(26):</u> Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (<u>i.e.</u>, absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (<u>i.e.</u>, potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

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

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

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

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

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

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

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

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

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

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

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made toTitle 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

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

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

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing

Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In

Shut-in Reserves are expected to be recovered from:

(1) completion intervals that are open at the time of the estimate but which have not yet started producing;

(2) wells which were shut-in for market conditions or pipeline connections; or

(3) wells not capable of production for mechanical reasons.

Behind-Pipe

Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

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

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

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

Exhibit 99.15

BKV CORPORATION

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

SEC Parameters
(NYMEX Alternate Pricing Scheme)

As of

December 31, 2023

/s/ Stephen E. Gardner
Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPELS REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

August 7, 2024

BKV Corporation
1200 17th Street, Suite 1850
Denver, CO 80202

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of BKV Corporation (BKV) as of December 31, 2023. The subject properties are located in the states of Pennsylvania and Texas. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations); except that they were based on varying price and constant cost assumptions provided by BKV. This pricing scenario is considered an “Alternate Pricing Scheme” in accordance with the above referenced Final Rule, Section II, Item B, Paragraph 3. Such forecasts were based on projected escalations or other forward-looking changes to current prices as noted. Our third party study, completed on January 2, 2024 and presented herein was prepared for public disclosure by BKV, as an alternate pricing scheme, in filings made with the SEC in accordance with the disclosure requirements set forth by the SEC regulations. The income data for the reserves volumes were estimated using NYMEX Futures Strip prices as of December 31, 2023.

The properties evaluated by Ryder Scott account for 100 percent of BKV’s total net proved liquid hydrocarbon and gas reserves as of December 31, 2023.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2023 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on varying NYMEX Futures Strip pricing assumptions provided by BKV and are explained in more detail later in this report. As a result of both economic and political forces, there is substantial uncertainty regarding the forecasting of future hydrocarbon prices. Consequently, actual future prices may vary considerably from the prices assumed in this report. The reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SEC PARAMETERS (NYMEX Alternate Pricing Scheme)
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
BKV Corporation
As of December 31, 2023

	Proved			
	Developed			Total
	Producing	Non-Producing	Undeveloped	Proved
Net Reserves				
Oil/Condensate – Mbbl	808	237	59	1,104
Plant Products – Mbbl	134,689	29,514	30,500	194,703
Gas – MMcf	2,791,791	193,157	790,838	3,775,786
MMCFE	3,604,773	371,663	974,192	4,950,628
Income Data ($M)				
Future Gross Revenue	$ 9,950,018	$ 986,815	$ 2,790,946	$ 13,727,779
Deductions	6,120,763	554,591	1,593,023	8,268,377
Future Net Income (FNI)	$ 3,829,255	$ 432,224	$ 1,197,923	$ 5,459,402
Discounted FNI @ 10%	$ 1,929,841	$ 85,654	$ 334,932	$ 2,350,427

PERCENTAGE OF PROVED RESERVES PER HYDROCARBON PHASE

OPERATED	**December 31, 2023**					
					Average Annual PDP Decline	
Operating Region	**Estimated Total Proved Reserves (MMCFE)**	**% Natural Gas**	**% Natural Gas Liquids**	**% Oil**	**Five Year**	**Ten Year**
Barnett	4,233,889	72.5%	27.3%	0.2%	7%	7%
NEPA	500,525	100.0%	0.0%	0.0%	10%	9%
Total	4,734,414	75.4%	24.5%	0.1%	7%	7%

NON OPERATED	**December 31, 2023**					
					Average Annual PDP Decline	
Operating Region	**Estimated Total Proved Reserves (MMCFE)**	**% Natural Gas**	**% Natural Gas Liquids**	**% Oil**	**Five Year**	**Ten Year**
Barnett	57,350	80.1%	19.5%	0.4%	9%	8%
NEPA	158,864	100.0%	0.0%	0.0%	9%	8%
Total	216,214	94.7%	5.2%	0.1%	9%	8%

TOTAL COMPANY	**December 31, 2023**					
					Average Annual PDP Decline	
Operating Region	**Estimated Total Proved Reserves (MMCFE)**	**% Natural Gas**	**% Natural Gas Liquids**	**% Oil**	**Five Year**	**Ten Year**
Barnett	4,291,239	72.6%	27.2%	0.2%	7%	7%
NEPA	659,389	100.0%	0.0%	0.0%	10%	8%
Total	4,950,628	76.3%	23.6%	0.1%	7%	7%

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (Mbbl). All gas volumes are expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas volumes are located. All gas reserves volumes are reported on an “as sold” basis. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M). The net reserves volumes are also shown herein on an equivalent unit basis wherein hydrocarbon liquid is converted to natural gas equivalent using a factor of 1 barrel of liquid per 6,000 cubic feet of natural gas equivalent. MMCFE means million cubic feet of natural gas equivalent.

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software packageARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of BKV. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes (including the Pennsylvania Impact Fee), development costs, and certain abandonment costs net of salvage. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Gas reserves account for approximately 81 percent and liquid hydrocarbon reserves account for the remaining 19 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income ($M) As of December 31, 2023	
Discount Rate Percent	Total Proved	
8	$	2,681,816
12	$	2,084,259
15	$	1,771,666
20	$	1,401,416

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definitions as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a),except that they are based on price parameters which allow for future changes in current economic conditions as discussed in other sections of this report, whereas the definition approved by the SEC assumes constant price parameters using the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The proved developed non-producing reserves included herein consist of the behind pipe status category.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At BKV's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

It should be noted that the estimated quantities of reserves presented in this report, which were based on NYMEX Futures Strip prices and constant current cost assumptions, may differ from the quantities of reserves which would be estimated using the price parameters prescribed by the SEC guidelines.

BKV's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of reserves actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which BKV owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The reserves for the properties included herein were estimated by performance methods or analogy. In general, the proved reserves attributable to producing wells and/or reservoirs were estimated by decline curve analysis, a performance method which utilized extrapolations of historical production and pressure data ending between August and October 2023, depending on the availability of data for a given case and in those cases where such data were considered to be definitive. For certain early-life cases, where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the estimates was considered to be inappropriate, producing reserves were estimated by analogy. The data utilized in our analysis were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

The reserves for the properties included herein attributable to the non-producing and the undeveloped status categories were estimated by analogy. The data utilized from the analogues were furnished to Ryder Scott by BKV or obtained from public data sources and were considered sufficient for the purpose thereof.

To estimate economically producible proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and the pricing assumptions provided to us, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined; which for this report, as stated previously, are based on pricing and cost parameters provided by and requested to be used by BKV.

BKV has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by BKV with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem taxes (including the Pennsylvania Impact Fee), production taxes, development costs, development plans, abandonment costs after salvage, product price assumptions, adjustments or differentials to product prices, and base maps. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by BKV. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations and are included as a price sensitivity case as allowed by SEC regulations.

Future Production Rates

For the producing wells included herein, our forecasts of future production rates and decline trends are based on the historical performance data of each well. If no production decline trend has been established, future decline trends were based on analogy to older, more established wells.

The initial performance of analogous wells was used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by BKV. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, well completions, and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The forecast hydrocarbon price parameters used in this report, based on NYMEX Futures Strip prices, were specified by BKV and are noted below. Estimates of future price parameters have been revised in the past because of changes in governmental policies, changes in hydrocarbon supply and demand, and variations in general economic conditions. The price parameters used in this report may be revised in the future for similar reasons. Gas prices may be subject to seasonal variations and other factors and may lead to periodic curtailments by both buyers and sellers.

BKV furnished us with the forecast of the average benchmark prices assumed to be in effect beginning on December 31, 2023 and throughout the life of the properties.

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, certain gas firm transportation fees, certain NGL fractionation and transportation fees, and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by BKV. The differentials furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose.

In addition, the table below summarizes the annual net volume weighted benchmark prices adjusted for differentials and referred to herein as the "average realized prices." The average realized prices shown in the table below were determined from the annual total future gross revenue before production taxes and the total net reserves, by reserves category for these properties.

Geographic Area	AVERAGE BENCHMARK PRICES		AVERAGE REALIZED PRICES		
United States	WTI - Cushing	Henry Hub	Oil/Cond	Plant Products	Gas
Year	$/Bbl	$/MMBtu	$/Bbl	$/Bbl	$/Mcf
2024	$ 71.60	$ 2.67	$ 64.17	$ 16.44	$ 2.07
2025	$ 68.32	$ 3.49	$ 60.89	$ 15.48	$ 2.91
2026	$ 65.37	$ 3.82	$ 57.95	$ 14.61	$ 3.26
2027	$ 63.32	$ 3.85	$ 55.90	$ 14.01	$ 3.29
2028	$ 62.02	$ 3.80	$ 54.59	$ 13.62	$ 3.24
2029	$ 61.28	$ 3.70	$ 53.86	$ 13.40	$ 3.14
2030+	$ 60.93	$ 3.64	$ 53.52	$ 13.30	$ 3.08
		Total Future Average Prices	$ 55.72	$ 13.74	$ 3.05

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by BKV and are based on the operating expense reports of BKV and include only those costs directly applicable to the leases or wells. Certain gas gathering and transportation costs were included as operating expenses. The operating costs furnished by BKV were reviewed by us for their reasonableness using information furnished by BKV for this purpose. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by BKV and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness using information furnished by BKV for this purpose.

The estimated net cost of abandonment after salvage was included for properties where certain abandonment costs net of salvage were provided by BKV, and which they requested be included in our report. The estimates of the net abandonment costs furnished by BKV were accepted without independent verification. We have made no inspections to determine if any other abandonment, decommissioning, and /or restoration costs may be necessary, in addition to the costs provided by BKV and included herein.

The proved developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with BKV's plans to develop these reserves as of December 31, 2023. The implementation of BKV's development plans as presented to us and incorporated herein is subject to the approval process adopted by BKV's management. As the result of our inquiries during the course of preparing this report, BKV has informed us that the development activities included herein have been subjected to and received the internal approvals required by BKV's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to BKV. BKV has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, BKV has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans.

Current costs used by BKV were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists receive professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to BKV. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott.The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by BKV. This report was based on forward looking price forecasts and may be filed as an additional pricing scenario to the SEC constant prices and costs case according to SEC guidelines.

For filings made with the SEC under the 1933 securities Act, we have provided our written consent for the references to our name as well as to the references to our third party report in the registration statement on Form S-1 by BKV. Our consent for such use is included as a separate exhibit to the filings made with the SEC by BKV.

We have provided BKV with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by BKV and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

/s/ Stephen E. Gardner
Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Stephen E. Gardner is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Gardner, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for ongoing reservoir evaluation studies worldwide, as well as for coordinating and supervising the evaluations of staff and consulting engineers of the company. Mr. Gardner is also a member of Ryder Scott's Board of Directors. Before joining Ryder Scott, Mr. Gardner served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Gardner's geographic and job specific experience, please refer to the Ryder Scott Company website at https://ryderscott.com/employees/denver-employees.

Mr. Gardner earned a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001 (summa cum laude). He is a licensed Professional Engineer in the States of Colorado and Texas. Mr. Gardner is a member of the Society of Petroleum Engineers (SPE) and a former director of the Society of Petroleum Evaluation Engineers (SPEE). He currently serves as an officer for SPEE at the international level.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Gardner fulfills. As part of his 2023 continuing education hours, Mr. Gardner attended multiple technical conferences, which covered a variety of reserves topics including analysis techniques for unconventional reservoirs, ESG issues, reserves definitions and guidelines, SEC comment letter trends, and others. Mr. Gardner was a featured speaker for geothermal resource evaluation and classification at an SPE technical workshop in August 2023. In addition, Mr. Gardner participated in various local technical seminars and other internal company training courses throughout the year covering topics such as reserves evaluation methods and evaluation software, ethics, M&A trends, regulatory issues, geothermal energy, SRMS, and more.

Based on his educational background, professional training and more than 18 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Gardner has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

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

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

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

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

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

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

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

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

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

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

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made toTitle 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

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

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

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves

Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing

Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In

Shut-in Reserves are expected to be recovered from:

(1)completion intervals that are open at the time of the estimate but which have not yet started producing;

(2)wells which were shut-in for market conditions or pipeline connections; or

(3)wells not capable of production for mechanical reasons.

Behind-Pipe

Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

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

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

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other

improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.