Results Live Here

ANNUAL REPORT 2024

788 MMCFE/D
OF NET
PRODUCTION

POWER
GENERATION
OF 7,360 GWH

165K METRIC
TONS OF CO_2
SEQUESTERED

-77.4% GROSS
DEBT REDUCTION

REFLECTING ON 2024

Letter from the CEO

Chris Kalnin, CEO
BKV Corporation

It's been a big year. And for BKV, that might be the understatement of the year.

While much of 2024 was unpredictable, I can confidently attribute our solid performance—along with the enviable position in which we find ourselves—to our values. For too many companies, lofty but empty aspirations are a common currency. Here, we proudly deliver on our promises and have the receipts to prove it.

Results live here
Robust results from our upstream operations fueled many of our initiatives, including CCUS. Our power business is gaining momentum as we engage with prospects in the energy-hungry data center sector. Maintaining a strong balance sheet gives us the flexibility to advance our business across all vectors.

Did I mention we made our debut on the New York Stock Exchange last September? With the success of our initial public offering, we opened a new chapter in BKV's journey—one defined by greater visibility, accountability and opportunity. Yes, 2024 was truly transformational.

Combining traditional natural gas production with innovative decarbonization strategies, BKV is redefining the concept of what an energy company is and does. We believe our four core business lines—Upstream, Midstream, Power and CCUS—together create a scalable and sustainable energy platform. As the world rapidly evolves, we are in a unique position to capitalize.

Solid to the core

At BKV, we believe our "closed loop strategy" is the winning formula—an approach that connects our natural gas production, midstream infrastructure, power generation and carbon capture capabilities in pursuit of a net-zero future. We are committed to vertically integrating portions of our business to improve commercial optimization across the full value chain, in turn creating scalable, long-term value. This model is designed to foster our ability to produce Carbon Sequestered Gas (CSG), enable the sale of this premium carbon-neutral natural gas product and, ultimately, deliver decarbonized power.

While we are still in the early phases of executing this strategy at scale, our foundation is strong and strategically aligned. In 2024 we produced approximately 788 MMcfe/d with more than 15 years of high-quality inventory. Our midstream footprint includes 778 miles of pipeline and 65 compressor stations. In power, we hold a 50% ownership stake in BKV-BPP Power, LLC, a joint venture anchored by two combined-cycle natural gas power plants in Temple, Texas. These plants boast a total generation capacity of approximately 1,500 megawatts, achieving a 57% average capacity factor and generating 7,360 gigawatt hours of electricity in 2024. BKV sees substantial growth potential in its Power JV, fueled by macroeconomic trends such as rising power demand in ERCOT, the rapid expansion of the data center market, and the accelerated adoption of AI.

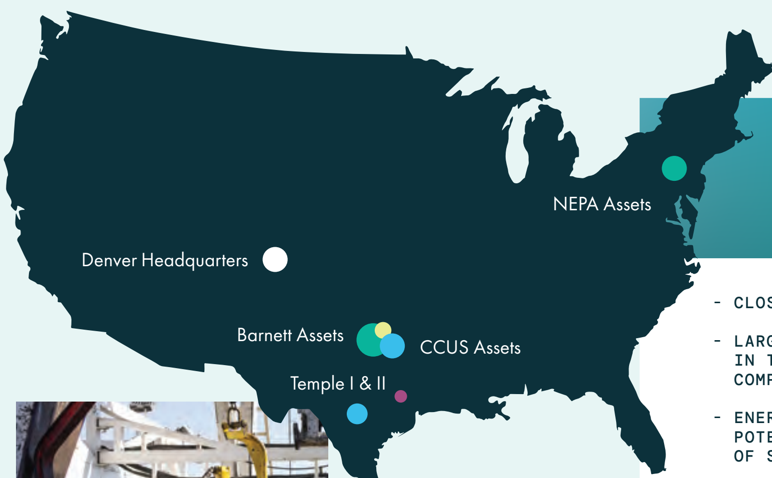
Upstream continued to serve as a cash engine for BKV in 2024, with particularly strong fourth-quarter results underscoring our competitive low decline rates, operational efficiency, and robust inventory. We believe these attributes will support durable adjusted free cash flow throughout the commodity price cycle—allowing us to reinvest strategically, increase production, and capture favorable pricing.

BKV is also securing a leadership position in the CCUS business, which we believe will play a vital role in decarbonizing the global economy. In operation for more than a year, Barnett Zero achieved life-to-date sequestration of approximately 173,325 metric tons of CO_2 through December 31, 2024. With meaningful progress toward multiple FIDs and a growing pipeline of projects, BKV is solidifying its leadership in this space.

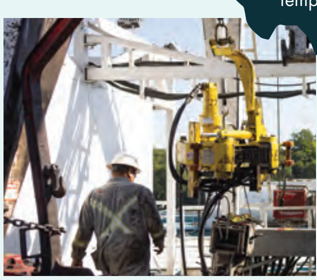
Financial discipline and shareholder appreciation

With all this going on, BKV still managed to underspend its 2024 capital expenditure guidance—a 28% year-over-year reduction—demonstrating operational efficiency with agility in responding to market conditions. By year's end, we had $436 million in total liquidity with a net leverage ratio of 0.65x, leaving us well-equipped for investments and acquisitions in areas of promising long-term value such as CCUS and power generation.

Employing our proactive hedging strategy, we expect to hedge at least 50% of our production for the next 24 months to mitigate exposure to commodity price fluctuations. All in all, we're balancing immediate cash flow with long-term returns, prioritizing governance and shareholder engagement while ensuring a resilient foundation for future growth.



- CLOSED LOOP STRATEGY
- LARGEST NATURAL GAS PRODUCER IN THE BARNETT WITH COMPLEMENTARY ASSETS IN NEPA
- ENERGY SOLUTIONS MARKET GROWTH POTENTIAL AT THE CONFLUENCE OF SIGNIFICANT TRENDS



NATURAL GAS UPSTREAM
POWER
CCUS
MIDSTREAM

2024

Love the view from here

We look forward to working with the new administration, which we believe is bullish on natural gas and domestic power generation. Domestically, carbon capture enjoys strong bipartisan support and our business model aligns perfectly with those sentiments. Economic incentives for our initiatives, like the 45Q tax credit enacted by Congress and codified by the IRS, have been supported across multiple administrations.

While we can't predict the future, we monitor the world closely and are built to respond and adapt decisively. With a strong balance sheet, a unique combination of business lines and proximity to the booming DFW data center market—BKV appears poised for tremendous growth by even the most conservative estimates.

Which brings us back to our most valued asset

Our word. Delivering on our promises has been the bedrock of BKV's success. It's built our reputation, inspired our employees and earned the trust of our partners and stakeholders. Whether it's our contributions to the communities we serve, the environment we cherish or the business we grow, we mean what we say—which means everything in my opinion.

When you own your challenges, you own your future. And that's a great place to live.

Chris Kalnin, CEO
BKV Corporation

ECONOMIC INCENTIVES FOR OUR INITIATIVES

UNIQUE COMBINATION OF BUSINESS LINES

PROXIMITY TO BOOMING DFW DATA CENTER MARKET

"Delivering on our promises has been the bedrock of BKV's success. It's built our reputation, inspired our employees and earned the trust of our partners and stakeholders."

Board of Directors

Chris Kalnin
Director since 2020
Chief Executive Officer, BKV Corporation

Chanin Vongkusolkit
Director and Chairman of the Board since 2020
Founder and Chairman of the Board, Banpu Public Company Limited

Somruedee Chaimongkol
Director since 2020
Committees - Audit & Risks; Compensation
Director of Banpu North America Corporation, Former Chief Executive Officer and Director of Banpu Public Company Limited

Joe Davis
Director since 2020
Committees - Nominations and Governance
Former Chief Operating Officer, Kalnin Ventures

Akaraphong Dayananda
Director since 2020
Committees - Nominations and Governance
Director and President, Banpu North America Corporation

Kirana Limpaphayom
Director since 2023
Chief Operating Officer of Banpu Public Company Limited and Chief Executive Officer of Banpu Power US Corporation

Carla Mashinski
Director since 2022
Committees - Audit and Risks; Compensation
Former Chief Financial Officer and Administrative Officer, Cameron LNG

Thiti Mekavichai
Director since 2020
Committees - Nominations and Governance
Group Senior Vice President and Head of Oil & Gas, Banpu Public Company Limited

Charles Miller, III
Director since 2020
Committees - Compensation
Former Vice Chairman of Level 3 Communications

Sunit Patel
Director since 2022
Committees - Audits and Risks
Executive Vice President and Chief Financial Officer, Crown Castle Inc.

Anon Sirisaengtaksin
Director since 2020
Committees - Nominations and Governance
Director and Executive Advisor, Banpu Public Company Limited

Sinon Vongkusolkit
Director since 2022
Chief Executive Officer and Director of Banpu Public Company Limited

10-K

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2024

OR

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

For the transition period from to

Commission file number 001-42282

BKV CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**85-0886382**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1200 17th Street, Suite 2100 **Denver, Colorado**	**80202**
(Address of Principal Executive Offices)	(Zip Code)

(720) 375-9680

Registrant's telephone number, including area code

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock, $0.01 Par Value	BKV	New York Stock Exchange

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).

Yes ☒ No ☐

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

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

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

☒

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

☐

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements.

☒

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant’s executive officers during the relevant recovery period pursuant to §240.10D-1(b).

☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

Yes ☐ No ☒

As of June 30, 2024, the last business day of the registrant's most recently completed second fiscal quarter, there was no established public trading market for the registrant's equity securities. The registrant's common stock began trading on the New York Stock Exchange on September 26, 2024.

The registrant had 84,708,373 shares of common stock outstanding as of March 28, 2025.

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Part III of this Annual Report, to the extent not set forth herein, is incorporated by reference from the registrant's definitive 2025 Proxy Statement, to be filed no later than 120 days after the end of the fiscal year to which this Annual Report on Form 10-K relates.

Table of Contents

Glossary of Commonly Used Terms

The definitions set forth below include indicated terms in this Annual Report. All natural gas referred to in this Annual Report are stated at the legal pressure base of the state or area where the reserves exist and at 60 degrees Fahrenheit.

"***Adjusted Free Cash Flow***" refers to 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.

"***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 75.5%% of Banpu Power as of December 31, 2024.

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

"***Bbl***" refers to one stock tank barrel, of 42 U.S. gallons liquid volume, used in this Annual Report on Form 10-K in reference to crude oil or other liquid hydrocarbons.

"***Bcf***" refers to one billion cubic feet of natural gas or CO2.

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

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

"***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.

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

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

"CO_2" refers to carbon dioxide.

"CO_2e" refers to carbon dioxide equivalent.

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

"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.

"***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.

"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.

"***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.

"***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.

"***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.

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

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

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

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

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

"***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.

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

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

"***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.

"***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.

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

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

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

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

"***OPIS***" refers to a Dow Jones Company that surveys and collects price information and publishes benchmarks for various energy commodities.

"***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.

"***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.

"***PUCT***" refers to the Public Utility Commission of Texas.

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

"***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 a third party environmental assessment and verification process and has a current TrustWell rating.

"***Revolving Credit Agreement***" refers to $100.0 million of commitments of unsecured revolving loans with Bangkok Bank Public Company Limited (New York Branch).

"***Revolving Credit Facilities***" refers to an uncommitted credit facilities with Oversea Chinese Banking Corporation and Standard Chartered Bank of up to $55.0 million and $50.0 million, respectively.

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

"***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.

"***Section 45Q tax credits***" refers to tax credits provided under Section 45Q of the Code.

"***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.

"***Term Loan Credit Agreement***" refers to a credit agreement with a syndicate of banks and Bangkok Bank Public Company Limited (New York Branch), as the administrative agent, which included $600.0 million of commitments for term loans used to solely to fund a portion of the purchase price for the Exxon Barnett Acquisition.

"***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.

"***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.

SUMMARY OF RISK FACTORS

We believe that the principal risks associated with our business, and consequently the principal risks associated with an investment in our equity or debt securities, generally fall within the following categories:

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 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 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 identified a material weakness 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.

We describe these risks in greater detail under Item 1A., “*Risk Factors*.”

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact contained in this Annual Report on Form 10-K, 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 Annual Report on Form 10-K, 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 terms 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.

Forward-looking statements contained in this Annual Report on Form 10-K include, but are not limited to, statements about:

- 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;
- volatility in natural gas, NGL, and oil prices;
- our dividend policy;
- our drilling plans and the timing and amount of future production of natural gas, NGL, and oil;
- our hedging strategy and results;
- 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 develop, 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 final investment decision 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, 2, and 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, 2, and 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, and the continuation of government tax incentives applicable thereto;
- 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.

PART I

ITEM 1. BUSINESS

Overview

BKV Corporation ("BKV," the "Company," "our," "we," and "us") is 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 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.

Initial Public Offering

On September 27, 2024, we completed our initial public offering ("IPO") of 15,000,000 shares of our common stock at a price to the public of $18.00 per share. We also granted the underwriters of our IPO a 30-day option to purchase up to 2,250,000 additional shares of common stock on the same terms. The underwriters partially exercised the option and, on October 28, 2024, purchased 701,003 additional shares of common stock. These sales of our common stock resulted in net proceeds of $265.7 million after deducting underwriter fees and offering expenses of $17.0 million. All shares sold were registered pursuant to a registration statement on Form S-1 (File No. 333-268469), as amended, which was declared effective by the Securities and Exchange Commission (the "SEC") on September 25, 2024. We used $200.0 million to pay down a portion of our outstanding borrowings, including interest, under our RBL Credit Agreement, and $50.0 million to repay the outstanding balance, including interest, under our related party loan with BNAC, our majority stockholder. The remaining amounts were used for growth capital expenditures and other general corporate purposes.

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. We believe the following strategic priorities will help drive value creation and long-term success.

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. 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 significantly reduce our annual GHG emissions and improve 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; and entering water share arrangements to reduce disposal and trucking cost. 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 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 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.

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 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.

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 refracturing, 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" support our core values and provide 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 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. As of December 31, 2024, our total acreage position was approximately 481,000 net acres, substantially all of which was held by production. For the year ended December 31, 2024, our net daily production averaged 788.0 MMcfe/d, consisting of approximately 79% natural gas and approximately 21% NGLs. As of December 31, 2024, our total proved reserves of 3,132 Bcfe had an estimated 8.2% year-over-year average base decline rate over the next 10 years.

As of December 31, 2024, our Barnett acreage position was approximately 462,000 net acres, substantially all of which was held by production. Our average daily Barnett production of approximately 671.0 MMcfe/d for the year ended December 31, 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 97.2% as of December 31, 2024 and an Effective NRI in the Barnett of approximately 80.2%. As of December 31, 2024, our NEPA acreage position was approximately 19,100 net acres, 97% of which was held by production. Our average net daily production of 117.0 MMcfe/d for the year ended December 31, 2024 consisted entirely of natural gas. As of December 31, 2024, we had an average working interest in our operated wells in NEPA of 91.5%.

As of December 31, 2024, we re-certified approximately 70% of our NEPA production and 48% of our Barnett production under the TrustWell environmental assessment program of Project Canary, an environmental certification and ESG data company. All of our TrustWell-certified production received a Gold rating from Project Canary, a strong rating that will enable us to sell Responsibly Sourced Gas. 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 ACR (formerly 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 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. We plan to commence delivery of Carbon Sequestered Gas upon completion of our certification process with the ACR (see "- *Carbon Capture, Utilization and Sequestration*" below).

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.

Barnett

In the Barnett, during the year ended December 31, 2024, approximately 188.1 MMcf/d of our gross production (approximately 26% 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. Our remaining Barnett production was gathered and processed primarily under an agreement with EnLink with no minimum volume commitments.

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 wholly-owned subsidiary, BKV Midstream, LLC, 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 had one minimum volume contract ("MVC") related to the assets acquired in the Exxon Barnett Acquisition for less than $1.0 million per year. This MVC was unfulfilled and resulted in immaterial unutilized gathering charges. The MVC-based contract expired in the third quarter of 2024. 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.

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.

NEPA

In NEPA, 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 Corners, LLC ("Chaffee") in June 2024, we sold our minority non-operated ownership interest in a Repsol Oil & Gas operated midstream system in NEPA. Our gross operated production volumes in NEPA are contractually gathered and treated primarily by three main third parties. As of December 31, 2024, approximately 58%, 35%, and 7% of our gross operated volumes in NEPA were further gathered and treated on UGI Energy Services Midstream Services, Williams Companies, 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 MVC terms, which expire in the second quarter of 2029. As of December 31, 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 to the gathering, central delivery point aggregation, and intra-basin transport, which represented 83% of the gross volumes produced from covered acreage.

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 December 31, 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.

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 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 February 2023, the BKV-BPP Power Joint Venture 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, BKV Energy has built a portfolio of over 55,000 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.

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 have engaged third parties to analyze and report the CO_2 injection volumes and environmental attributes of our sequestration projects, and we are working with the ACR to certify and register the environmental attributes associated with our CCUS projects as tradeable carbon credits. 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. 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. 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. In addition, in the future, we may sell carbon credits associated with our CCUS projects to unrelated third parties outside of our value chain. 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 (and retains) or purchases. 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.

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, debt financing, and federal grants, with the remaining capital needs being funded with cash flows from operations. We are currently in non-binding exclusive discussions concerning a potential joint venture with a third-party investor with the expectation to close in the first half of 2025. 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. For CCUS facilities placed in service after December 31, 2022, Section 45Q of the Code generally provides the capturing parties a tax credit of $85 per ton for CO_2 directly stored in geologic formations, 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. 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.

CCUS Projects

Currently, we have one operational CCUS project and are pursuing 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 42,000 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 $CO_{2}e$. Our projected timeline for commercial operations of these 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 the projects within the first five categories, as more fully described below.

Project	Status [(1)]	Actual or Forecasted Initiation of Sequestration Operations [(2)]	YE 2025 Forecasted Gross Rate (Mtpy CO_{2e}) [(3)]	YE 2026 Forecasted Gross Rate (Mtpy CO_{2e}) [(3)]	YE 2027 Forecasted Gross Rate (Mtpy CO_{2e}) [(3)]	Early 2030s Forecasted Gross Rate (Mtpy CO_{2e}) [(3)]
Barnett Zero	Operating	November 2023	0.13	0.14	0.15	0.21
Cotton Cove	FID	1H 2026	—	0.04	0.04	0.02
Eagle Ford	FID	1H 2026	—	0.09	0.09	0.08
Other NGP Projects	Pre-FID	2026 - 2029	—	0.04	0.52	2.71
Total NGP Projects	Varies	2023 - 2029	0.13	0.31	0.80	3.02
Total Industrial Projects	Pre-FID	2027 - 2028	—	—	0.14	11.25
Total Ethanol Projects	Pre-FID	2027 - 2029	—	—	0.11	1.36
Total	Varies	2023 - 2029	0.13	0.31	1.05	15.63

(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, the Eagle Ford 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 (and retains) or purchases.

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 these identified potential CCUS projects (or any other CCUS projects) with sufficient volumes of $CO_{2}e$ sequestration to achieve our Scope 1, 2, and 3 emissions goals on the timelines we anticipate. There can be no assurance that any of these identified potential CCUS projects, 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.

We estimate the aggregate investment required to develop the actual and potential CCUS projects identified above to be between approximately $1.3 - $1.6 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 $CO_{2}e$, landowners and other stakeholders. In order to achieve the projected timeline for commercial operations of such projects, we expect to fund up to 50% of the anticipated cost of these CCUS projects 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. If sufficient external funding is not available to help fund our CCUS business, 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.

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 Class II injection well that complies with standards applicable to Class VI wells. During 2024, the Barnett Zero Project achieved an annual sequestration rate of approximately 165,000 metric tons of CO_2e.

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 additional 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 32,000 metric tons of CO_2 per year. The Cotton Cove Project is held through the BKV-BPP Cotton Cove Joint Venture, which is 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 $18.4 million, of which we will be required to contribute approximately $9.4 million. We currently expect to be entitled to use the majority of the environmental attributes associated with such project 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.

Eagle Ford Project. On December 18, 2024, BKV dCarbon Ventures reached internal FID to develop our third CCUS project for the sequestration of waste emissions from a natural gas processing plant. This CCUS project, which we refer to as the Eagle Ford Project, will capture, compress, and then dispose of and geologically sequester the CO_2 waste stream generated as a byproduct of third-party natural gas processed by the plant. We estimate the Eagle Ford Project will geologically sequester up to approximately 90,000 metric tons of CO_{2e} per year. We currently estimate the total investment required for the Eagle Ford Project to be approximately $19.8 million and we expect to be entitled to use 100% of the environmental attributes associated with the project 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 third of our current modular line of identified potential NGP projects, in addition to the Barnett Zero and Cotton Cove Projects.

We are currently evaluating the expansion of the Barnett Zero and Cotton Cove Projects to pilot, and subsequently scale post-combustion carbon capture technology. This initiative 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.

Other NGP Projects

We have identified other potential NGP projects that we anticipate will achieve FID and commence initial sequestration operations at various points in 2026 through 2029. If approved and implemented, we anticipate that these projects would sequester third-party emissions, require a total capital investment by us of approximately $730.0 million by December 31, 2029, and subsequently achieve a combined forecasted annual sequestration volume of approximately 2.70 million metric tons of captured CO_2e per year.

Much of the carbon capture infrastructure required for these NGP projects is already in place. For example, we have amine towers to capture and concentrate CO_2 emissions to meet natural gas sales specifications. Also, we have secured definitive agreements for pore space leasehold for several projects, and have submitted or are working towards submitting well permits. 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 evaluating potential medium to higher concentration industrial projects to sequester third-party emissions, and anticipate these projects will achieve FID and commence initial sequestration operations at various points in 2027 and 2028. If approved and implemented, these projects would provide a combined forecasted annual sequestration volume of approximately 11.30 million metric tons per year of captured CO_2e.

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

In August 2023, High West 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.

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 U.S. Environmental Protection Agency (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 has indicated that it 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 the first half of 2025. 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 2027 and 2028.

Ethanol Projects

We have identified 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 projects would sequester third-party emissions, require a total capital investment by us of approximately $275 million by December 31, 2029, and subsequently achieve a combined forecasted annual sequestration volume of approximately 1.36 million metric tons of captured CO_2e per year.

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.

We are also currently evaluating additional 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 other project opportunities.

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 and the Eagle Ford Project, we have not reached FID with respect to or entered into the definitive agreements necessary to execute any of the other 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. 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 are targeting completion of third-party CCUS financing in 2025; however, there can be no assurance that we will be able to complete any CCUS financing on our targeted timeline, or at all. 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.*"

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. Our emissions estimates presented in this Form 10-K 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 requirements of the federal Clean Air Act GHG reporting program regulations for petroleum and natural gas systems, Subpart C and Subpart W, as applicable. These estimates will be updated annually to reflect any changes in activity, inventory, production throughput, and emissions reduction retrofits or equipment modifications, and published in our annual Sustainability Report.

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. 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 in connection with future growth 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 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 annual Scope 3 CO_{2e} emissions for the year ended December 31, 2023 were 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.

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, 2024, we had implemented elements of our "Pad of the Future" program on approximately 11,300 pneumatic devices and 1,500 pneumatic pumps of our existing wells in the Barnett and we have successfully completed the program with our upstream owned and operated assets in NEPA.

We are implementing this program on all of our owned and operating assets, which comprises of more than 6,000 of our existing wells (more than 17,000 pneumatic devices and 3,000 pneumatic pumps) by 2030 for an aggregate estimated cost of approximately \$40 to \$50 million. As of December 31, 2024, we completed the conversion of over 60% of our pneumatic devices and pneumatic pumps and incurred costs of approximately \$18.7 million to date.

Emissions Monitoring. 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.

Solar Renewable Credits. 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 completed construction and began generating power in August 2024. The BKV-BPP Power Joint Venture has obtained permits for and constructed 2.5 MW and is evaluating the option of 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 solar facility is expected to generate SRECs sufficient to offset up to 32% of the Scope 2 emissions from our owned and operated upstream and natural gas midstream business as of December 31, 2023.

CCUS. Further, as discussed under "— *Carbon Capture, Utilization, and Sequestration*" above, we believe that the Barnett Zero Project, together with the Cotton Cove Project, the Eagle Ford Project, and the additional pre-FID projects for the capture and sequestration of third-party emissions that we have identified, have a combined annual forecasted sequestration volume of approximately 15.63 Mtpy CO_{2e} by the early 2030s. Although we have not secured external financing, reached FID, or entered into the definitive agreements necessary to execute any of the additional pre-FID projects we have identified, 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.

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 potential CCUS projects we have identified (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. In addition, in the future, we may sell carbon credits associated with our CCUS projects to unrelated third parties outside our value chain. 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 (and retains) 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 estimated 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 additional 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 15.6 Mtpy CO_{2e} by the early 2030s, which represents a majority of our current Scope 1, 2, and 3 annual emissions from our owned and operated upstream and natural gas midstream businesses. In addition, 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 has 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 other 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 or retain 100% of the environmental attributes associated with our CCUS projects as discussed above, which may negatively impact our net zero strategy, potentially delaying or preventing our progress towards achieving our net zero goals.

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 to help fund our CCUS business, 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.

Our Acreage

The following table summarizes our acreage position as of December 31, 2024:

	Developed		Undeveloped		Total	
Operating Region	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Barnett [(1)]	641,923	426,314	40,134	35,496	682,057	461,810
NEPA	21,677	18,312	1,467	785	23,144	19,097
Total	663,600	444,626	41,601	36,281	705,201	480,907

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

[(1)] Includes acreage acquired during 2021 from Jamestown Resources, LLC, Larchmont Resources, LLC, and Pelican Energy, LLC, for which acreage the leasehold interest is derived from unit-based assignments and includes 133,470 gross and 3,318 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 approximately 1.02% in 2025, 0.51% in 2026, and 0.003% in 2027.

Our Productive Wells

The following table sets forth our gross and net productive natural gas and oil wells as of December 31, 2024:

Operated Wells:	Producing Natural Gas Wells		Producing Oil Wells		Total		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Barnett	5,492	5,340	7	7	5,499	5,347	97.2 %
NEPA	142	130	—	—	142	130	91.5 %
Total	5,634	5,470	7	7	5,641	5,477	97.1 %
Non-Operated Wells:							
Barnett	924	90	1	—	925	90	9.7 %
NEPA	35	—	—	—	35	—	— %
Total	959	90	1	—	960	90	9.4 %
Total:							
Barnett	6,416	5,430	8	7	6,424	5,437	84.6 %
NEPA	177	130	—	—	177	130	73.4 %
Total	6,593	5,560	8	7	6,601	5,567	84.3 %

The following table sets forth our gross and net productive natural gas and oil wells as of December 31, 2023:

Operated Wells:	Producing Natural Gas Wells		Producing Oil Wells		Total		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
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:							
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:

Operated Wells:	Producing Natural Gas Wells Gross	Producing Natural Gas Wells Net	Producing Oil Wells Gross	Producing Oil Wells Net	Total Gross	Total Net	Average Working Interest
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:							
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 %

Drilling, Refrac, and Restimulation Activity

During the year ended December 31, 2024, six wells were drilled in the Barnett. As of December 31, 2024, we had four wells (four net) drilled and uncompleted in the Barnett and no wells drilled and uncompleted in NEPA. In addition, as of December 31, 2024, we had four wells (four net) in the process of being drilled in the Barnett. During the period, ten wells were completed in the Barnett and three wells were completed in NEPA, all of which were net productive. As of December 31, 2024, all drilled and uncompleted wells from prior year programs had been completed and began production.

During the year ended December 31, 2023, we drilled three wells in NEPA and fifteen 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.

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.

We also maintain a restimulation program in the Barnett to develop economic incremental reserves in existing wellbores and arrest the overall field production decline. During the years ended December 31, 2024, 2023, and 2022 we completed three, 32, and 163 horizontal and vertical restimulations, respectively. Additionally, as of December 31, 2024, we had 28 proved undeveloped horizontal locations and 221 proved developed non-producing refrac candidates in the Barnett. For a discussion of how we identify drilling locations and refrac candidates, please see "—D*etermination of Identified Drilling and Refracture Locations*."

Production Volumes and Average Unit Prices

The following table summarizes sales volumes, sales prices and production cost information for our net natural gas and production for the years ended December 31, 2024, 2023, and 2022.

	Year ended December 31,		
	2024	2023	2022
Production Volumes			
Barnett:			
Natural gas (MMcf)	185,857.3	198,099.4	166,771.0
Natural gas liquids (MBbl)	9,857.7	10,553.6	10,187.0
Oil (MBbl)	96.0	118.6	140.0
Total Barnett (Bcfe)	245.6	262.1	228.7
NEPA:			
Natural gas (MMcf)	42,825.3	51,666.9	50,814.0
Natural gas liquids (MBbl)	—	—	—
Oil (MBbl)	—	—	—
Total NEPA (Bcfe)	42.8	51.7	50.8
Total Company (Bcfe)	288.4	313.8	279.5
Average Sales Prices (excluding impact of derivative settlements)			
Barnett:			
Natural gas ($/Mcf)	$ 1.87	$ 2.28	$ 6.38
Natural gas liquids ($/Bbl)	$ 16.79	$ 17.80	$ 30.58
Oil ($/Bbl)	$ 68.81	$ 71.21	$ 84.76
NEPA:			
Natural gas ($/Mcf)	$ 0.91	$ 1.12	$ 4.85
Natural gas liquids ($/Bbl)	$ —	$ —	$ —
Oil ($/Bbl)	$ —	$ —	$ —
Total Company ($/Mcfe)	$ 1.93	$ 2.25	$ 5.84
Average Sales Prices (including the impact of derivative prices) (1)			
Natural gas ($/Mcf)	$ 2.10	$ 2.23	$ 3.72
Natural gas liquids ($/Bbl)	$ 17.19	$ 17.55	$ 27.78
Oil ($/Bbl)	$ 68.81	$ 70.97	$ 84.76
Total Company ($/Mcfe)	$ 2.28	$ 2.39	$ 3.95
Average Production Cost ($/Mcfe) (2)			
Barnett	$ 1.43	$ 1.48	$ 1.43
NEPA	$ 0.20	$ 0.24	$ 0.26
Total Company	$ 1.25	$ 1.27	$ 1.22

(1) Impact of derivative prices excludes $13.3 million and $46.7 million of gains on derivative contract terminations for the years ended December 31, 2024 and 2023, respectively, and $158.4 million of derivative contract terminations for the year ended December 31, 2022.

(2) Excludes natural gas and oil ad valorem and production taxes.

For additional information on pricing see, *Management's Discussion and Analysis of Financial Condition and Results of Operations* in Item 7 of Part II in this Annual Report on Form 10-K.

Determination of Identified Drilling and Refracture Locations

Proved Drilling and Refracture Locations

As of December 31, 2024, we had approximately 28 gross (26 net) proved undeveloped horizontal drilling locations and 221 gross (205 net) proved developed non-producing refrac candidates at SEC reserves pricing. 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

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 (i) 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.

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, 2024, 2023, and 2022. These reserves estimates were prepared in accordance with the rules and regulations of the SEC regarding oil and natural gas reserves reporting. For more information about our reserves volumes and values, see "— *Preparation of Reserves Estimates and Internal Controls*" and Ryder Scott's summary reserve reports, which are filed as exhibits to this Annual Report on Form 10-K.

The following table provides our estimated proved reserves information prepared by Ryder Scott as of December 31, 2024, 2023, and 2022 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, 2024, as compared to December 31, 2023, is primarily due to lower commodity pricing. 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. There are numerous uncertainties inherent in estimating quantities of natural gas, NGL, and oil reserves and their values, including many factors beyond our control.

Estimated SEC Reserves (1)

	December 31,		
	2024	**2023**	**2022**
Estimated proved developed reserves:			
Natural gas (MMcf)	2,059,984	2,443,072	3,798,027
Producing	1,951,322	2,290,025	3,468,901
Non-producing	108,662	153,047	329,126
Natural gas liquids (MBbls)	134,017	156,399	170,840
Producing	113,739	129,260	157,585
Non-producing	20,278	27,139	13,255
Oil (MBbls)	878	992	1,111
Producing	713	802	1,111
Non-producing	165	190	—
Total estimated proved developed reserves (MMcfe)	2,869,354	3,387,418	4,829,733
Producing	2,638,034	3,070,397	4,421,077
Non-producing	231,320	317,021	408,656
Estimated proved undeveloped reserves:			
Natural gas (MMcf)	176,047	539,423	1,057,649
Natural gas liquids (MBbls)	13,605	27,766	40,660
Oil (MBbls)	813	59	758
Total estimated proved undeveloped reserves (MMcfe) (2), (3)	262,555	706,373	1,306,157
Estimated total proved reserves:			
Natural gas (MMcf)	2,236,031	2,982,495	4,855,676
Natural gas liquids (MBbls)	147,622	184,165	211,500
Oil (MBbls)	1,691	1,051	1,869
Total estimated proved reserves (MMcfe)	3,131,909	4,093,791	6,135,890
Standardized Measure (millions)	$ 633	$ 1,062	$ 6,994
PV-10 (millions) (4), (5)	$ 672	$ 1,232	$ 8,955

(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, 2024 were $2.13 per MMBtu (Henry Hub), $75.48 per Bbl (WTI Cushing) and NGL pricing equal to 29.5% of WTI Cushing, (ii) 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, and (iii) 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.

(2) Proved undeveloped reserves as of December 31, 2024 and 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 were part of a development plan adopted by management indicating that such locations were scheduled to be drilled within five years of initial booking.

(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) 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.

(5) The following table provides a reconciliation of the Standardized Measure to PV-10 with respect to estimated proved reserves as of December 31, 2024, 2023, and 2022:

	December 31,		
	2024	2023	2022
PV-10 (millions)	$ 672	$ 1,232	$ 8,955
Present value of future income taxes discounted at 10%	(39)	(170)	(1,961)
Standardized Measure	$ 633	$ 1,062	$ 6,994

During the years ended December 31, 2024, 2023, and 2022, we incurred costs of approximately $22.8, $37.7 million, and $54.0 million, respectively, to convert 57.6 Bcfe, 31.9 Bcfe, and 74.0 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, 2024, 2023, and 2022 were approximately $135.1 million, $360.7 million, and $1,089.6 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 during the year ended December 31, 2024 focused on refracturing under-stimulated wells and designing and drilling new wells in the Barnett, and completing drilled and uncompleted wells in NEPA. Our proved undeveloped reserves, as of December 31, 2024, are scheduled to be developed within five years of their initial disclosure.

2024 Activity

During the year ended December 31, 2024, our proved reserves decreased by 961.9 Bcfe. The decrease in proved reserves was primarily attributable to decreased commodity pricing and changes in our planned drilling activity, which resulted in total downward revisions of 714.9 Bcfe. In addition, in June 2024, we sold our wholly-owned subsidiary, Chaffee and certain of our non-operated upstream assets in BKV Chelsea, LLC (“Chelsea”) decreasing reserves by 150.0 Bcfe. As discussed below, these decreases were partially offset by extensions and discoveries and improved recoveries we experienced in 2024, which resulted in net increases to proved reserves of 139.2 Bcfe and 52.2 Bcfe, respectively. We produced 288.4 Bcfe during the year ended December 31, 2024.

Revisions of previous estimates primarily consisted of downward revisions to proved developed reserves and proved undeveloped reserves of 235.6 Bcfe and 213.7 Bcfe, respectively, as a result of lower average pricing during 2024 for natural gas, NGLs, and oil. Additional downward revisions were made to proved undeveloped reserves of 265.6 Bcfe due to lower capital spend and the resulting reduction in drilling activity during 2024. Changes to our drilling schedule moved the development of 38.0 gross (35.1 net) locations in NEPA and the Barnett beyond the SEC requirement of developing

PUD reserves five years from initial booking. These 38.0 gross (35.1 net) locations remain in inventory of unproved locations to be developed outside of the next five years. The drilling schedule changes reflect our ongoing commitment to optimize the long-term plan to best develop our assets, maximize cash flow, and produce economic returns.

Extensions and discoveries added 139.2 Bcfe of proved undeveloped reserves across 98.0 gross (89.4 net) locations, driven by our optimized capital allocation and enhanced drilling program, which reduced costs and extended lateral lengths during the year ended December 31, 2024.

Improved recoveries added 52.2 Bcfe of proved developed reserves achieved through the continued enhancement of recovery techniques applied to producing wells during the year ended December 31, 2024.

Sale of minerals in place consisted of 103.9 Bcfe and 46.1 Bcfe of divested proved developed reserves and proved undeveloped reserves, respectively, of Chaffee assets and certain non-operating upstream assets in Chelsea, both sold in June 2024, which represented 330.0 gross (39.6 net) locations in NEPA.

Conversions of proved undeveloped reserves to proved developed reserves consisted of 57.6 Bcfe related to the completion of 8.0 gross (7.9 net) wells during the year ended December 31, 2024 that were converted to proved developed wells, previously classified as proved undeveloped.

2023 Activity

During the year ended December 31, 2023, our proved reserves decreased by 2,042.1 Bcfe. The decrease in proved reserves was primarily attributable to decreased commodity pricing and changes in our 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 in 2023, which resulted in net increases to proved reserves of 227.8 Bcfe and 30.2 Bcfe, respectively. We 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 lower capital spend and the resulting reduction in drilling activity during 2023. Changes to our drilling schedule moved the development of 112.0 gross (104.8 net) locations in NEPA and the Barnett beyond the SEC requirement of developing PUD reserves five years from initial booking. These 112.0 gross (104.8 net) locations remain in inventory of unproved locations to be developed outside of the next five years. The drilling schedule changes reflect our 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 our 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 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, our 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. We 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 further discussed below. 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. These locations are more rich in NGLs than the previously recognized locations removed from the 2021 drilling schedule as discussed above. 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.

Purchase 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.

Estimated Reserves at NYMEX Strip Pricing

The following table provides our total estimated proved reserves information prepared by Ryder Scott as of December 31, 2024, using NYMEX strip prices as of market close on December 31, 2024 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, 2024. The historical 12-month pricing average in our December 31, 2024 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, 2024. 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, 2024
Estimated proved developed reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	2,766,814
Producing	2,582,672
Non-producing	184,142
Natural gas liquids (MBbls)	153,449
Producing	124,543
Non-producing	28,906
Oil (MBbls)	993
Producing	731
Non-producing	262
Total estimated proved developed reserves (MMcfe)	3,693,466
Producing	3,334,316
Non-producing	359,150
Estimated proved undeveloped reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	939,776
Natural gas liquids (MBbls)	46,381
Oil (MBbls)	1,038
Total estimated proved undeveloped reserves (MMcfe) [(1), (2)]	1,224,290
Estimated total proved reserves at NYMEX Strip Pricing:	
Natural gas (MMcf)	3,706,590
Natural gas liquids (MBbls)	199,830
Oil (MBbls)	2,031
Total estimated proved reserves (MMcfe)	4,917,756
Standardized Measure (millions)	$ 1,990
PV-10 (millions) [(3)]	$ 2,446

(1) Proved undeveloped reserves December 31, 2024 are part of a development plan that has been adopted by management indicating that such locations are scheduled to be drilled within five years.

(2) 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.

(3) 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, 2024:

	December 31, 2024
PV-10 (millions)	$ 2,446
Present value of future income taxes discounted at 10%	(456)
Standardized Measure	$ 1,990

Preparation of Reserves Estimates and Internal Controls

Our reserves estimates as of December 31, 2024, 2023, and 2022 included in this Annual Report on Form 10-K 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)." A copy of Ryder Scott's reserve reports are included as exhibits to this Annual Report on Form 10-K.

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 Corporate Development Officer, Ethan Ngo, is primarily responsible for overseeing the independent reserves engineers during the process. Mr. Ngo has over 16 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.

Enterprise Risk Management

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.

Customers and Product Marketing

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. 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 December 31, 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 11 years, with an average remaining duration of 4.6 years as of December 31, 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 175,000 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 205,716 MMBtu/d of firm transport on Energy Transfer and Houston Pipe Line Company LP, which expires in 2027. The contract with Energy Transfer and Houston Pipe Line provides access to the NGPL-TxOk market.

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, the Temple Plants hold 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 December 31, 2024, our minimum aggregate required payments per year under firm gathering and transportation agreements were approximately $68.6 million for 2025, $66.7 million for 2026, $59.0 million for 2027, $53.1 million for 2028, $34.3 million for 2029, and $38.9 million for 2030 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.

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.

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 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.

Human Capital Resources

As of December 31, 2024, we had a total of 366 employees. We hire independent contractors on an as needed basis. 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 meetings 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 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, which 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 various financial, health, and/or 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.

We have a whistleblower policy supported by a confidential ethics and compliance hotline (available via call-in or an online submission portal) and a required manager and employee online training program that includes topics such as business ethics, human rights and diversity, equity and inclusion. Completion of this training is tracked on a quarterly basis to ensure accountability.

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 to ensure alignment with the dynamic rights of our workforce. Our Human Rights Policy extends to all our operations, as well as partners, contractors, 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-up obligations, 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 December 31, 2024 we have recorded asset retirement obligations of $201.2 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 management or possible release of hydrocarbons or other wastes was not under our control. These properties, and any wastes that may have been released on them, have the potential to be sources of CERCLA liability, 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, including Texas, also have environmental cleanup laws analogous to CERCLA.

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 exemption from regulation as hazardous waste under 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 non-exploration and production industrial wastes that may be regulated as hazardous wastes if such wastes have hazardous characteristics or are listed as hazardous under RCRA.

***Oil Pollution Ac*t**. 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 Clean Water Act, or 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 promulgated wastewater pretreatment standards that 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. For additional information, see "*Risk Factors - Risks Related to Environmental, Legal Compliance and Regulatory Matters - We may face unanticipated water and other waste disposal costs as a result of increased water-related regulations."*

Safe Drinking Water Act. The Safe Drinking Water Act, or 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 the procurement of 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 or state 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, North Dakota, and West Virginia, 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 rules requiring the disclosure of chemicals used in hydraulic fracturing fluids, 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 ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAP") 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, former 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 March 8, 2024, the EPA published its Methane Rule, which took effect on May 7, 2024 and established requirements for methane emissions from existing and modified oil and gas sources and imposed additional requirements for new sources with respect to methane and volatile organic chemical emissions, including sources not previously regulated under the oil and gas source category. The Methane Rule is currently being challenged in federal courts. Motions filed by a coalition of states to stay the rule pending the challenge were denied by the D.C. Circuit Court of Appeals and by the U.S. Supreme Court and, as a result, the Methane Rule remains in effect pending the outcome of the challenges. It remains to be seen what impact the new

Trump Administration will have on these and other climate-related measures taken under the Biden Administration. 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.

Collectively, these rulemaking actions, 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 ("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. The EPA's May 2024 final power plant GHG emissions rule is being challenged by a coalition of states and industry groups. Motions to stay the rule pending the challenge were denied by the D.C. Circuit Court of Appeals and by the U.S. Supreme Court and, as a result, the rule remains in effect pending the outcome of the challenges. It remains to be seen what impact the new Trump Administration will have on this and other climate-related measures taken under the Biden administration. In any event, 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 March 8, 2024, the EPA published its Methane Rule, which took effect on May 7, 2024 and established 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 Methane Rule is being challenged in the courts, but remains in effect pending the outcome of the challenges. It remains to be seen what impact the new Trump Administration will have on this and other climate-related measures taken under the Biden Administration. 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. 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. On January 20, 2025, the new Trump Administration signed an executive order to formally exit the Paris Agreement. It remains to be seen what the impact of this action will have on other climate-related measures taken under the Biden Administration.

The United States Congress ("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 Jumpstart Our Business Startups Act of 2012 (the "JOBS Act") 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 imposed several new climate-related requirements on oil and gas operations and the Inflation Reduction Act of 2022 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. It remains to be seen what impact the new Trump Administration will have on the climate-related measures taken under the Biden administration.

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 U.S. state governors 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. In addition, California enacted two new climate disclosure laws in September 2023 that (1) require U.S.-based businesses with total annual revenues over one billion dollars and doing business in California to annually report their Scope 1, 2, and 3 GHG emissions, and (2) require U.S.-based businesses with total annual revenues over five hundred million dollars and doing business in California to prepare biennial risk reports disclosing the entity's climate-related financial risk and measures adopted to reduce and adapt to climate-related financial risk. A lawsuit challenging the new California climate disclosure laws was filed in a federal district court in California on January 30, 2024. On November 5, 2024, the U.S. District Court for the Central District of California denied a motion for summary judgment that sought to declare the two new climate disclosure laws invalid. The California Air Resources Board is required to adopt regulations implementing the new California disclosure requirements, but has not, to date, issued any such regulations. Furthermore, if the SEC's proposed climate disclosure requirements are adopted on substantially similar terms as proposed, we will be required to incur significant time and money to comply with the disclosure requirements and may be required to modify certain of our operations. These compliance costs could adversely impact our future business.

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 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 Endangered Species Act, or 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, in April 2023, a new White House Office of Environmental Justice was created and all federal agencies were directed 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 whether the new Trump Administration will continue these requirements and how federal agencies will undertake to comply, but the development and application of these environmental justice requirements may result in permit uncertainty and delays for our activities that require federal approvals.

Operating Hazards and Insurance

Natural gas and NGL 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. 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.

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.

Address, Internet Website, and Availability of Public Filings

Our principal executive offices are located at 1200 17th Street, Suite 2100, Denver, Colorado 80202, and our telephone number is (720) 375-9680. We also maintain an offices in Fort Worth, Texas as well as several regional field offices. Our website is *www.bkv.com*.

We furnish or file our Annual Reports on Form 10-K, our Quarterly Reports on Form 10-Q, our Current Reports on Form 8-K, and amendments to such reports and other documents with the SEC under the Exchange Act. The SEC also maintains an internet website at www.sec.gov that contains reports, proxy and information statements and other information regarding issuers, including us, that file electronically with the SEC. We also make these documents available free of charge at *www.bkv.com* under the "Investors" link as soon as reasonably practicable after they are filed or furnished with the SEC. Our Sustainability Report is also available on our website.

Information on our website is not incorporated into this Annual Report on Form 10-K or our other filings with the SEC and is not a part of them.

Information about our Executive Officers (as of March 31, 2025)

Name	Age	Current Title (Year Initially Elected an Executive Officer)
Christopher P. Kalnin	47	Chief Executive Officer (2020)
John T. Jimenez [(1)]	55	Chief Financial Officer (2021)
Eric S. Jacobsen [(2)]	54	President — Upstream (2020)
Barry S. Turcotte	54	Chief Accounting Officer (2022)
Lindsay B. Larrick	42	Chief Legal and Chief Administrative Officer (2022)
Ethan Ngo	43	Chief Corporate Development Officer (2022)
Mary Rita Valois	65	Chief Information Officer (2023)

[(1)] As previously reported in the Company's Current Report on Form 8-K filed on February 3, 2025 (the "Current Report"), Mr. Jimenez will step down from the position of Chief Financial Officer on March 31, 2025, and will be succeeded by Mr. David Tameron. Mr. Jimenez will serve as a senior advisor to the Company until his retirement on May 15, 2025. For additional information, see the Current Report.

[(2)] As previously reported in the Company's Current Report, the Company eliminated the position of Chief Operating Officer and appointed Mr. Jacobsen to a new position, President — Upstream, effective February 3, 2025.

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, and has served as a member of the board of managers of the BKV-BPP Power Joint Venture since October 2021. He also worked at Kalnin Ventures, the fund manager of BKV Oil and Gas Capital Partners, L.P., 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., 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 President — Upstream of the Company since February 2025 and as a member of the board of managers of the BKV-BPP Power Joint Venture since March 2025. Mr. Jacobsen previously served as Chief Operating Officer of the Company from its formation in May 2020 to February 2025. 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 Administrative Officer of the Company since February 2025 and as Chief Legal Officer of the Company since July 2022. She has also served as a member of the board of managers of the BKV-BPP Power Joint Venture since February 2025. Ms. Larrick previously served as Vice President, General Counsel and Corporate Secretary of the Company from its formation in May 2020 to July 2022, and 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 Corporate Development Officer of the Company since February 2025 and as a member of the board of managers of the BKV-BPP Power Joint Venture since June 2024. Mr. Ngo previously served as Chief Technical Resources Officer of the Company from July 2022 to February 2025 and, prior to that, as Senior Vice President, Engineering of the Company from its formation in May 2020 to July 2022. 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.

ITEM 1A. RISK FACTORS

The following risk factors should be considered in evaluating our business and future prospects, in addition to other information included in this Annual Report. Additional risk factors not presently known to us, or currently considered immaterial, may also have an adverse impact on our business, financial condition, and results of operations. If any of the events described below occur, our business, financial condition, or results from operations may suffer and the trading price of our common stock could be adversely affected.

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 amounts we expect to invest 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 2022, high of $9.85 and low of $3.46; in 2023, high of $3.78 and low of $1.74; and in 2024, high of $13.20 and low of $1.21.

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 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, 2022 through December 31, 2024, the Henry Hub natural gas spot price reached a high of $13.20 per MMBtu on January 13, 2024 and a low of $1.21 per MMBtu on November 11, 2024. Henry Hub natural gas spot prices average in 2022 was $6.45 per MMBtu, which trended higher due to production freeze-offs and high net withdrawals of natural gas from storage. In 2023 and 2024, natural gas spot prices averaged $2.57 per MMBtu and $2.21 per MMBtu, respectively, as a result of a warmer-than-normal winters, increased U.S. natural gas supply, and a combination of higher production and higher storage inventories given these mild winters.

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 62%, 61%, and 69%, for the years ended December 31, 2024, 2023, and 2022, 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 timeframe 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, NGLs, 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.

The present value of future net revenues from our proved reserves is not the same as 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, NGLs, 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, 2024, approximately 469.3 Bcfe, or 15.0%, 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 estimated reserves, 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 December 31, 2024, we carried unproved natural gas, NGL, and oil property costs of $10.8 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 provides us with a network 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 with Atmos and Energy Transfer and firm storage with Energy Transfer. We are obligated under these arrangements to pay a demand charge for firm transportation and storage capacity rights on most of 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.

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 well operations, 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, 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.

We may experience certain issues and encounter risks in our drilling operations, including:

- 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;
- 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; and
- other typical shale basin drilling challenges and risks.

We experience certain issues and encounter risks in our hydraulic fracturing, workover, and completions activities, including:

- 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;
- 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; and
- 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, and we could incur material write-downs of unevaluated properties, which may cause the value of our undeveloped acreage to 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 December 31, 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 year ended December 31, 2024, approximately 75% of our gross operated production volumes were gathered and processed by a third party. 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 third parties, as well as the midstream operations involving our assets depend upon a number of factors outside of our control. These factors include the operator's schedule and level of capital investment, expertise, financial resources, collaboration with other participants in drilling wells, and the 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 years ended December 31, 2024, 2023, and 2022, the portion of BKV's earnings in the BKV-BPP Power Joint Venture were $10.4 million, $16.9 million, and $8.5 million, respectively, and our interest in the earnings on the BKV-BPP Power Joint Venture represented approximately 1.8%, 1.7%, and 0.8% 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 ten members, five of whom are appointed by us and five of whom are appointed by BPPUS. Of the five members appointed by us, one is an employee of Banpu who also serves on our board of directors. The BKV-BPP Power LLC Agreement delegates to a general manager appointed by the Power JV Board the authority to manage and administer the business 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. Consequently, BKV-BPP Power may not take certain material actions without the consent of BPPUS. The specified matters reserved for approval by at least a majority of the members of the Power JV Board include, among other things, (i) 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, (ii) the wind up, dissolution, liquidation, commencement, or any filing or petition for a voluntary bankruptcy, reorganization, debt arrangement involving BKV-BPP Power, (iii) any plan to or initial sale of BKV-BPP Power or other equity interests to the public, (iv) any amendments, restatements, or revocations of BKV-BPP Power's organizational documents, (v) the execution, amendment, or termination of a material contract, and (vi) any amendment to or deviation from the dividend policy of the joint venture or any of its subsidiaries. Additionally, 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 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 Power JV Board, which debt payments would reduce the amount of cash that might otherwise be available for distributions to us.

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 Temple Plant's generating capacity below expected levels, reducing potential cash distributions to BPPUS and us. Unanticipated capital expenditures associated with maintaining, upgrading, or repairing the Temple Plants 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 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 these facilities based on our assessment that such activity will provide adequate financial returns. The modifications to these facilities require 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 the Temple Plants or their firm natural gas storage service at the Bammel storage facility. We cannot ensure that we will be successful in the future in obtaining the commercial contracts necessary to facilitate direct delivery of our natural gas production to the Temple Plants on commercially reasonable terms or at all.

We cannot ensure 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 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 may not be 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 power prices, which could have an adverse effect on our financial condition. For example, as of December 31, 2024, BKV-BPP Power had unrealized losses of $13.2 million on its derivative instruments as a result of increased power prices; of the $13.2 million, $5.5 million of these losses pertain to two 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 the Temple Plants 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*."

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 seeks to hedge this exposure whenever possible, but hedging instruments may not be economically feasible or available in the required quantities. Additionally, certain components of energy prices cannot be hedged, and there is risk that hedge providers may fail to fulfill their obligations. BKV-BPP Retail's hedging activities do not prevent it from exposure to risk, primarily price fluctuations, including those caused by transmission congestion or extreme weather, which may 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 for future periods and finance the purchases upfront until we can recover such amounts from our customers. We also rely on an energy supplier to facilitate our energy and hedge our purchases. If we are unable to renew this agreement or if our energy supplier's credit rating declines, our ability to economically purchase energy and hedges could be impacted. Further, any challenges in securing credit or liquidity on commercially reasonable terms could adversely impact our retail business.

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

Our success depends on the expertise of key members of our management team whose loss could disrupt our business operations. Additionally, the PUCT requires us to have one or more officers or managers with at least 15 years of combined experience in the competitive energy industry. Losing certain key personnel could impact our ability to continue operating a retail electric business and jeopardize 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 to impose additional regulations on the retail business and increase our compliance obligations. Additionally, customer complaints and compliance violations could damage our relationship with the PUCT and potentially jeopardize our REP certificate. Losing our REP certificate, LSE registration, or QSE registration would prevent us from continuing to operate in the retail business.

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, the Cotton Cove Project, and the Eagle Ford Project face, and any of our potential future CCUS projects, including the pipeline of CCUS projects currently under evaluation, will face operational, technological, regulatory, and financial risks. These risks include the possibility that EnLink, BPPUS, or any of our other future counterparties to a CCUS project, may not meet their financial or performance obligations related to the CCUS project. Moreover, the economics of our operational and potential CCUS projects depend on financial and tax incentives, including the enhanced Section 45Q tax credits implemented by the Inflation Reduction Act of 2022. If we are unable to obtain the Section 45Q tax credits included in our financial assumptions for any reason, including as a result of any change in policy changes, government spending measures, or U.S. presidential executive actions, any of our proposed CCUS projects may no longer be commercially viable and may not be completed.

Although we have identified potential CCUS projects in addition to the Barnett Zero Project, Cotton Cove Project, and the Eagle Ford 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 potential projects we have identified and, as such, we cannot guarantee that any of those potential projects will reach FID or be completed. Additionally, we cannot ensure 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 (and retains) 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 the Eagle Ford Project, or 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 no 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 needed for the entire geologic formation. 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 Cotton Cove Project, the Eagle Ford Project, and the additional pre-FID projects identified in this Annual Report on Form 10-K to be between approximately $1.3 - $1.6 billion between now and the end of 2030. We invested $36.7 million towards the Barnett Zero Project, and we currently estimate the total investment required for the Cotton Cove Project to be approximately $18.4 million, of which we will be required to contribute approximately $9.4 million.

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, debt financing, 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 the 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 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. Of the four members appointed by BKV dCarbon Ventures, none are employees of Banpu who also serve on our board of directors. Additionally, 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, such as (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; (ix) making decisions related to a possible initial public offering of BKV-BPP Cotton Cove; or (x) causing BKV-BPP Cotton Cove to make distributions.

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. In addition, 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 for any reason, including as a result of policy changes, government spending adjustments, or U.S. presidential executive actions, many of our proposed CCUS projects may no longer be commercially viable and may not be completed. We cannot ensure 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 in a timely manner, 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 continue to successfully operate the Barnett Zero Project with EnLink in the Barnett, or successfully develop the Cotton Cove Project with BPPUS, the Eagle Ford Project, 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, which include the following:

- 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;
- 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; and
- 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.

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 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 right-of-ways or leases or if such right-of-ways 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, 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, 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, NGLs, 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 cash flows 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.

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 the U.S. Federal Reserve interest rate adjustments in response, the availability and cost of credit, and the 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 and 2024 with potential economic downturns or recessions in parts of the United States and globally, which continues into 2025 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 increases 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.

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 the 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 extent to which any future pandemic, epidemic, outbreak, or other public health event could impact our business will depend on numerous evolving factors that we may not be able to accurately predict.

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 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.

Our estimated sequestration rates from our CCUS business and our emissions reduction expected from our initiatives and our associated expected emission 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.

Our ability to develop and operate large-scale CCUS projects involves significant risks and uncertainties, and we may be unable to execute some or all of these projects, including those for which we have reached FID, within the expected timeline, on terms acceptable to us, or at all. 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 and the Eagle Ford Project, we have not reached FID with respect to or entered into the definitive agreements necessary to execute any of the other 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. 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.

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. In addition, in the future, we may sell carbon credits associated with our CCUS projects to unrelated third parties outside of our value chain. 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 (and retains) 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, we may purchase various credits or offsets that may be deemed to mitigate our emissions impact instead of actual changes in our emissions reduction performance in order to meet our emissions reduction goals. 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. There can be no assurances that we will be able to execute on our strategy to meet our Scope 1, 2, and 3 owned and operated upstream and natural gas midstream emissions goals.

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

As of March 31, 2025, we had outstanding debt of $200.0 million, which consisted entirely of revolving borrowings under the RBL Credit Agreement. We intend to use borrowings under the RBL Credit Agreement for working capital purposes, to fund capital expenditures for the acquisition, 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 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; and/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 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 covenants.

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 RBL Credit Agreement or any future debt agreement or if we default under the terms of 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 covenants, may be affected by events beyond our control. Further, if, any person or group (other than Banpu and its controlled affiliates, excluding portfolio companies and operating companies) acquires 35% or more of BKV's equity interests, or if any person or group acquires a greater percentage of BKV'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 following September 27, 2024, the date of our IPO whereby Banpu has agreed 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 our common stock or any securities convertible into or exercisable or exchangeable for shares of our common stock, subject to certain exceptions) 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 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'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. Sustained, decreased natural gas prices could cause non-compliance with the Company's financial covenants. Non-compliance with financial debt covenants would 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.

Our borrowings under the RBL Credit Agreement expose us to interest rate risk.

Our results of operations are exposed to interest rate risk associated with borrowings under the RBL Credit Agreement, which bear interest at rates based on the Secured Overnight Financing Rate ("SOFR") or an alternative floating interest rate benchmark. Interest rates remained elevated throughout 2023 and the first half of 2024 as the U.S. Federal Reserve sought to control inflation. Interest rates have slightly decreased during the fourth quarter of 2024 and are currently expected to continue to decrease in 2025 and possibly into 2026. 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 consolidated statements of operations 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 years ended December 31, 2024 and 2023, we had realized gains of $112.5 million and $90.2 million, respectively, of which $13.3 million of the $112.5 million, and $46.7 million of the $90.2 million of gains related to early termination of hedges. These gains are attributable to decreases in underlying commodity prices and volatility in energy markets. However, for the year ended December 31, 2022, we incurred realized losses on derivatives of $688.5 million, $158.4 million of which related to early termination of hedges. For the year ended December 31, 2024, we incurred unrealized losses on derivatives of $146.7 million, and for the years ended December 31, 2023 and 2022, we incurred unrealized gains of $148.6 million and $58.8 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 December 31, 2024, we have hedged 348,750 MMBtu/d, 228,750 MMBtu/d, and 80,000 MMBtu/d for 2025, 2026, and 2027, 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 December 31, 2024, we have hedged 13,275 Bbl/d and 10,500 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.

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, including cybersecurity, management liability, automobile liability, third-party liability, workers' compensation, employer's liability, 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 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.

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. 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. They may also be better positioned to contract for drilling, production and workover equipment, pay higher wages to secure trained personnel, and absorb the burden of current 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. Additionally, there is strong competition for desirable natural gas, NGL, and oil-producing properties, energy companies, undeveloped leases, drilling rights, and CCUS projects. Further, the current inflation may affect us more severely 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 business faces 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, including but not limited to human error, power outages, computer and telecommunication failures, natural disasters, fraud or malice, social engineering or phishing attacks, viruses or malware, and other cyberattacks, such as denial-of-service or ransomware attacks. Reports indicate that certain entities or groups, including cybercriminals, competitors, and nation state actors, have mounted cyber-attacks on businesses and other organizations solely to disable or disrupt computer systems, disrupt operations, and, in some cases, steal data. While we maintain a robust cybersecurity program, which includes administrative, technical, and organizational safeguards, a significant cyberattack or other cyber incident (whether involving our systems, those of a critical third-party, or both) could disrupt our operations and result in downtime, loss of revenue, harm to the Company’s reputation, or the loss, theft, corruption, or unauthorized release of critical data of us or those with whom we do business, as well as result in higher costs to correct and remedy the effects of such incidents, including potential extortion payments associated with ransomware or ransom demands. Our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities, and infrastructure may also 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 that could lead to losses of sensitive information, critical infrastructure, or capabilities essential to our operations, all of which could have a material adverse effect on our business, 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 to which we have limited visibility and control. Even though we carry cyber insurance that may provide insurance coverage under certain circumstances, we might suffer losses as a result of a security breach or cyber incident that exceeds the coverage available under our policy or for which we do not have coverage, and we cannot be certain that cyber insurance will continue to be available to us on commercially reasonable terms, or at all. 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, particularly amidst the increased adoption of artificial intelligence technologies, are becoming more sophisticated. 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, future 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 BKV 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 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" as defined in Section 2(a)(19) of the Securities Act of 1933, as amended (the "Securities Act"), including as modified by 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 Public Company Accounting Oversight Board ("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, less information will be provided about our executive compensation and internal control over financial reporting compared to non-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, 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 occasionally create and publish voluntary disclosures regarding ESG matters, many of the statements in these disclosures are based on hypothetical expectations and assumptions, which may not be representative of current or actual risks or events, or forecasts of expected risks or events, including the associated costs. 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 that in connection with the new Trump Administration, there will likely be regulatory uncertainty with respect to ESG matters at the federal level, disclosure-related, and otherwise. However, this may cause some states to increase levels of ESG-related regulation, along with increased stakeholder and non-governmental organizational engagement in ESG matters. 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 recognize that standards and expectations for carbon accounting as well as the methods for measuring GHG emissions and environmental attributes, such as offsets and renewable energy credits, are evolving. Our current and future approaches to measuring and implementing reductions and achieving goals like "net zero" or a "closed-loop" system may be viewed by some stakeholders as inconsistent with emerging or common best practices depending on individual interpretations or expectations. If our approaches to such matters are inconsistent with particular stakeholder expectations, we may face increased scrutiny, criticism, regulatory actions, and investor concerns, 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 labeling 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” and RSG programs, 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 contract with a subsidiary of Kiewit. In certain cases, our emissions reduction and other ESG efforts rely on third parties, whose actions or timelines may not align with our expectations. Additionally, even if we achieve our net zero goals as described herein, we may not fully realize the intended benefits if other stakeholders disagree with our goals, structure, methodology, accounting practices, or data sources in achieving them.

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 reinterpretations of new ones, may require us to change our internal assessment criteria, limit the use of certain marketing claims, reduce the benefit of initiatives we implemented, or adversely affect our operations.

Increasing attention to global climate change has resulted in increased investor attention and 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, 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 these allegations 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 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 or development programs or production activities and affect our access to capital for potential growth projects. For example, the international community gathered in Glasgow, Scotland, U.K. at the 26th Conference to the Parties on the UN Framework Convention on Climate Change ("COP26"), and 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, former 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. It remains uncertain how the new Trump Administration will influence ESG policy at the federal level, but risks identified in this section resulting from other drivers are expected to persist in any event.

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, NGLs, and oil.

Energy conservation measures, alternative fuel requirements, governmental requirements for renewable energy resources, increasing consumer demand for alternatives to natural gas, NGLs, 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 may include damages to our facilities from powerful winds or rising waters in low lying areas, disruption to production due to climate-related damages or increased operational costs, the need for less efficient or non-routine operating practices caused by climate effects, or increased insurance costs resulting from 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 guarantee 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. Congress, from time to time, has considered legislation to amend the 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 may consider 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 cash flow.

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 was contemplated, but ultimately rejected in Texas. If Texas were to decide to limit the production of crude oil 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 that apply to our operations 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 former 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, former President Biden signed a resolution passed by Congress under the Congressional Review Act nullifying the September 2020 rule, effectively reinstating the prior standards. On March 8, 2024, the EPA published its Methane Rule, which took effect on May 7, 2024 and established 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 sources not previously regulated under the oil and gas source category. The Methane Rule is currently being challenged in the federal courts, but it remains in effect pending the outcome of the challenges. It remains to be seen what impact the new Trump Administration will have on these and other climate-related measures taken under the Biden Administration. 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 U.S. 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. It remains to be seen what impact the new Trump Administration will have on these and other climate-related measures taken under the Biden Administration.

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, former President Biden 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 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. Relevantly, the United States and the 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. Former President Biden also agreed in November 2021 to cooperate with Chinese President 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 and it remains to be seen whether the new Trump Administration will take actions that will affect the participation of the United States in the Paris Agreement or related commitments of the United States and, if so, what the impact of such actions will be. 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, former President Biden issued an executive order that called 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. 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. It is anticipated that the policy of the Trump administration will reduce the focus on climate change and environmental justice at the federal level, but it is too soon to predict what overall effects the change in administration will have on these issues. As of February 2025, the Trump administration has revoked multiple Biden administration executive orders regarding climate change.

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, although the SEC has voluntary stayed the effective date of the rule. We continue to monitor the status of this 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 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 RCRA, which imposes requirements for the generation, treatment, storage, transport, disposal, and cleanup of nonhazardous and hazardous wastes;

• the 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 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 depend on these contractors to provide trained labor as well as equipment that is properly designed, maintained, and tailored to their specific 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 delivery requirements and complaint-based state regulation regarding our rates, terms, and conditions of service. Our NGL gathering pipelines and operations may also fall under 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, operational, 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. We may have to shut in wells, reduce drilling activities, or upgrade facilities for water handling or treatment if any of the following occur: (i) water produced from our projects fails to meet the quality requirements set by relevant regulatory agencies, (ii) our wells produce water in excess of the allowed volumetric permit limits, (iii) the disposal wells fail to comply with applicable regulatory requirements, or (iv) we are unable to secure access to disposal wells with sufficient capacity to handle all of the produced water. 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 U.S., 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 issued a notice of 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. To implement these changes outlined in the 2016 notice of proposed rulemaking, PHMSA promulgated three separate major rules (collectively referred to as the "Gas Mega Rule"), which include rules focused on: the safety of gas transmission pipelines, the safety of hazardous liquid pipelines, and enhanced emergency order procedures.

The first component of the Gas Mega Rule, the gas transmission rule, was finalized in October 2019 and 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. PHMSA promulgated the second component of the Gas Mega Rule in November

2021, extending federal safety requirements to onshore gas gathering pipelines with large diameters and high operating pressures.

The final of the three components of the Gas Mega Rule was published on August 24, 2022 and took effect on May 24, 2023 and 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 2025, the maximum civil penalties PHMSA can impose are $272,926 per pipeline safety violation per day, with a maximum of $2,729,245 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 are always 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 either determine that we are required to make a mandatory filing, submit to CFIUS review on a voluntary basis, or 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 or implemented, and it is not possible at this time to predict when, or if, this will be accomplished.

Effective March 15, 2021, the CFTC implemented its final rule concerning speculative position limits, adopting new and amended federal spot-month limits for 2025 physical commodity derivatives. Under this rule, 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.

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. 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. This final rule was amended on February 24, 2021 to permit the application of a minimum transfer amount of up to $50,000 for each separately managed account of a legal entity that is a counterparty to a swap dealer or a major swap participant in an uncleared swap transaction and to permit the application of separate minimum transfer amounts for initial margin and variation margin.

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 or amend 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 financial counterparties to post additional capital as a result of entering into uncleared financial derivatives with us, which 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, who 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 our cash flows may be 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, 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 cash flows.

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

The regulatory environment surrounding cybersecurity, data privacy and protection, and the unauthorized disclosure of personal or confidential information is constantly evolving and can be subject to significant change. New laws and requirements pose increasingly complex compliance challenges and could potentially elevate our costs. Any failure or perceived failure to comply with these laws and regulations could result in significant penalties, legal liability, judgments, and negative publicity, changes in our business practices, and adverse impacts to our business. We continue to monitor and assess the impact of these laws, such as the California Consumer Privacy Act and the Cyber Incident Reporting for Critical Infrastructure Act, and other similar legislation. If we are not able to adjust to changing laws, regulations, and standards relating to privacy or cybersecurity, our business may be materially harmed. As noted above, we are also subject to the possibility of cyber events, which themselves may result in a violation of these privacy and data security laws. Additionally, if we acquire a company that has violated or is not in compliance with applicable privacy and cybersecurity laws, we may incur significant liabilities and penalties as a result.

Risks Related to Our Relationship with Banpu and its Affiliates

Banpu is our controlling stockholder and exercises a significant influence over us, and investors' ability to influence matters requiring stockholder approval may be limited.

As of March 31, 2025, Banpu indirectly owns approximately 75.4% of our outstanding common stock. Our outstanding common stock is entitled to one vote per share. As a result of this ownership, Banpu has a significant influence on our affairs and its voting power constitutes a significant majority 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, under our Stockholders' Agreement, as 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) until September 27, 2025 (the first anniversary of the completion of our IPO), at least three board seats will not be BNAC designees, (ii) from September 27, 2025 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.

Further, if 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 significant 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 ten-member board of managers, five of whom are appointed by us and five of whom are appointed by BPPUS. Of the five members appointed by us, one is an employee of Banpu who also serves on our board of directors. 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. Of the three members appointed by us, none are employees of Banpu who also serve on our board of directors. 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 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 our IPO on September 27, 2024, we relied on Banpu and its affiliates for the capital investments necessary to fund our business through loan proceeds and other contributions. Following this date, 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, debt financing, and federal grants, with the remaining capital needs being funded with cash flows from operations. Our future operating performance and ability 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. Banpu continues 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 are currently a "controlled company" within the meaning of the NYSE rules and, as a result, may qualify for and could rely on exemptions from certain corporate governance requirements.

Banpu beneficially controls a significant majority of the voting power of our outstanding voting stock. Pursuant to our Stockholders' Agreement, BNAC, through ownership interests in us held by BNAC and its affiliates, has certain rights to designate individuals for nomination to our board of directors. 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. Accordingly, the same protections afforded to stockholders of companies that are subject to all of the NYSE corporate governance requirements are not afforded to our stockholders.

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 our status as a publicly traded company;
- 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 and 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. 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 due to the fact that any such person pursues or acquires any corporate opportunity for, or recommends or transfers any corporate 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.

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. Seven of our directors are 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 of 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.

Risks Related to 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 Item 1A, "*Risk Factors*," and under "*Cautionary Note Regarding Forward-Looking Statements*" included elsewhere herein. Many of these risks and uncertainties are beyond our control, such as declines in commodity prices, the speculative nature of estimating natural gas and NGL reserves, and 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.

We have identified a material weakness 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 December 31, 2024, a material weakness 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 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 (i) audit adjustments to income tax benefit, income taxes payable to related party, and deferred tax assets and liabilities in the consolidated financial statements as of December 31, 2021 and for the year then ended, (ii) an immaterial audit adjustment to the supplemental cash flow 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 as of and for the year ended December 31, 2023, (iii) audit adjustments to deferred tax liabilities, net and additional paid-in capital as of December 31, 2024, and (iv), the revision of our previously issued financial statements for the interim and annual periods included in the years ended December 31, 2021, 2022, and 2023, and interim periods included in the year ended December 31, 2024.

We have begun to take steps towards remediating this material weakness related to the accounting for our income taxes primarily by designing and implementing additional internal controls, including those related to 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 this material weakness, the measures we have taken, and plan to take, may not be effective.

In addition, as disclosed in connection with our IPO, as of December 31, 2023, 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 two additional material weaknesses in our internal controls. 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.

We have remediated the material weaknesses related to the communication of relevant information among departments to account for stock awards and common stock with certain put rights and the communication and evaluation of our contract reviews by designing and maintaining effective controls to communicate relevant information between departments.

Each of the material weaknesses described above could have resulted 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.

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 guarantee 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 as a public entity. 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 common stock.

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.

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.

As of March 31, 2025, Banpu owns 63,877,614 shares of common stock, representing approximately 75.4% of our total outstanding common stock, and management, directors, and other employee and non-employee stockholders, collectively, own 20,830,759 shares of common stock, representing approximately 24.6% of our total outstanding common stock. Such shares are subject to the lock-up agreements between such parties and the underwriters, but may be sold into the market following the expiration of the lock-up agreement.

In addition, our Stockholders' Agreement 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 within 180-days from September 27, 2024, the date of our IPO. The sale by an insider may have a negative effect on the market price of our common stock.

Furthermore, we may issue additional shares of common stock or convertible securities in subsequent public offerings. 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 is not 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 is not subject to conversion, redemption or sinking fund provisions.

The representatives of the underwriters in our IPO may waive or release parties to the lock-up agreements entered into in connection with our IPO, 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 September 27, 2024, the date of our IPO. 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.

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 designates 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 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 Delaware General Corporation Law 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

BKV employs a comprehensive cybersecurity strategy to protect against threats that could compromise sensitive information, disrupt data or systems, or jeopardize the security of facilities and infrastructure, including third-party processing plants and pipelines.

Managing Material Risks & Integrated Overall Risk Management

BKV has strategically integrated cybersecurity risk management into its broader enterprise risk management framework to promote a company-wide culture of cyber risk awareness. BKV's Chief Information Officer ("CIO") and Manager of Cybersecurity work closely with its information technology ("IT") department to continuously evaluate and address cybersecurity risks in alignment with business objectives, operational needs, and industry-accepted standards, such as the Center for Internet Security (CIS) Critical Security Controls and National Institute of Standards and Technology (NIST) frameworks.

The Company has processes and procedures in place to monitor the prevention, detection, mitigation, and remediation of cybersecurity risks. These include but are not limited to:

- Maintaining and regularly updating a defined and practiced incident response plan ("IRP");
- Maintaining cyber insurance coverage;
- Employing appropriate incident prevention and detection software, such as antivirus, anti-malware, firewall, endpoint detection, and identity and access management;
- Executing scheduled, recurring server and infrastructure patching processes;
- Maintaining a defined disaster recovery policy and employing backup/disaster recovery software, where appropriate;
- Educating, training, and testing employees on information security practices and identification of potential cybersecurity risks and threats; and
- Ensuring familiarity and compliance with cybersecurity frameworks where appropriate.

Engaging Third Parties on Risk Management

Recognizing the complexity and evolving nature of cybersecurity risk, BKV engages with external experts, including, but not limited to a managed security service provider (“MSSP”), the Cybersecurity Operations Center (“CSOC”) team to evaluate, monitor, and test BKV's cyber management systems and related cyber risks. The Company's collaboration with these third parties includes audits, threat and vulnerability assessments, IRP testing, company-wide monitoring of cybersecurity risks, and consultation on security enhancements. Third-party experts have assisted BKV in conducting cross-functional tabletop exercises and quarterly strategic meetings as well as developing comprehensive remediation plans following cybersecurity assessments.

Managing Third Party Risk

BKV's cybersecurity approach also assesses the risks associated with the use of vendors, service providers, and other third parties that provide information system services, process information on its behalf, or have access to its information systems, and has processes in place to oversee and manage these risks. In addition to the minimum security and control standards, these processes include other quality control measures as well. BKV also maintains ongoing monitoring to support continuous compliance with its cybersecurity standards, and regularly updates and patches third-party applications and tools when vulnerabilities are discovered.

Risks from Cybersecurity Incidents

As of March 31, 2025, BKV has not been subject to any material cybersecurity incidents and we are not aware of any cybersecurity risks that are reasonably likely to materially affect the Company, its operations, or financial standing. For additional information about cybersecurity risks associated with our business, see Item 1A, “*Risk Factors*.”

Governance

Risk Management Personnel

We have an enterprise risk committee that includes our executive leadership team and other senior members within our legal, IT, finance and accounting, and operational departments, which oversees BKV's operational, strategic, and corporate-level risks, including risk management.

Our comprehensive cybersecurity risk management is led by our CIO who brings over 30 years of extensive experience in information technology with a specialization in cybersecurity. Her expertise spans global information systems and data, cybersecurity operations, security management strategies and tools, security assessment and remediation, as well as the design and implementation of controls to prevent and detect cybersecurity threats. BKV’s cybersecurity risk management program is overseen by management at multiple levels. The CIO and Manager of Cybersecurity play key roles in assessing, monitoring, and managing the Company's cybersecurity risks. The CIO Cybersecurity governance also is supported by our IT department and CSOC. These stakeholders meet monthly to review the monthly cybersecurity assessment and remediation report. The IT department conducts extensive reviews of our systems, networks, and data infrastructure to identify potential cybersecurity threats and vulnerabilities and implements systems and tools to remediate perceived risks. These tools are designed to prevent and detect activities or events that could pose a cybersecurity risk to our business. Our third party CSOC team provides 24-hour monitoring to detect and respond to suspicious activity in real time.

Monitor Cybersecurity Incidents

The CIO and Manager of Cybersecurity are continually informed and updated about the latest developments in cybersecurity, including emerging threats and innovative risk management techniques. They implement and oversee processes for the 24/7/365 monitoring of our information systems as well as ongoing threat assessment monitoring. The deployment of advanced security measures, regular system audits to identify potential vulnerabilities, and periodic cyber assessment exercises support these programmatic efforts. In the event of a cybersecurity incident, the Company is equipped with a defined and practiced IRP. This plan includes immediate actions to mitigate the impact and long-term strategies for remediation and prevention of future incidents.

Board of Director Oversight

Our Audit & Risk Committee provides oversight of cybersecurity risk in connection with BKV's comprehensive cybersecurity strategy and receives regular quarterly updates on our ongoing assessment of cybersecurity risks, threats, and data security programs to prevent and detect breaches and attacks against BKV. The CIO and other experts, as necessary, provide the Audit & Risks Committee quarterly updates that encompass a broad range of topics, including but not limited to:

- Current cybersecurity threat landscape and emerging threats;

- Status of ongoing cybersecurity initiatives and strategies;
- Incident reports and learnings from unique cybersecurity events, including those of other companies;
- Compliance status and efforts with regulatory requirements and industry standards; and
- Benchmarked data on the performance of certain aspects of our cybersecurity program relative to our peers

The Audit & Risk Committee meets quarterly to discuss areas that are potentially high risk to the Company.

ITEM 2. PROPERTIES

Information regarding our properties is included in Item 1. "*Business*" and in *Note 19 - Supplemental Oil and Gas Disclosures (unaudited)* incorporated herein.

ITEM 3. 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.

This information with respect to this Item 3. "*Legal Proceedings*" is set forth in Item 8 of Part II, *Financial Statements and Supplementary Data*, in *Note 16 - Commitments and Contingencies* incorporated herein.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES

Common Stock and Shareholders

Our common stock is traded on the NYSE under the symbol "BKV." Our common stock has been trading on the NYSE since September 26, 2024. Prior to trading on the NYSE, there was no established public trading market for our common stock.

On March 28, 2025, the closing price of our common stock was $20.74 and we had approximately 1,000 stockholders of record, excluding stockholders for whom shares are held in "nominee" or "street" name.

Dividends

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.

Recent Sales of Unregistered Securities

None.

Use of Proceeds

There has been no material change in the expected use of the net proceeds from our IPO as described in our prospectus filed on September 27, 2024 and other periodic reports previously filed with the SEC.

Securities Authorized for Issuance Under Equity Compensation Plans

2024 Equity and Incentive Compensation Plan

Our 2024 Equity and Incentive Compensation Plan (the "2024 Plan") became effective immediately prior to the consummation of the IPO. The 2024 Plan permits the grant of awards to the non-employee directors, officers, and other employees of BKV and its controlled subsidiaries in order to provide incentives and rewards for service and/or performance. We may grant stock options, appreciation rights, restricted stock, restricted stock units ("RSUs"), performance shares, performance units, cash incentive awards, and certain other awards based on or related to shares of our common stock. Under the 2024 Plan, we can issue up to 5,000,000 shares of its common stock, which are subject to adjustment to reflect any extraordinary cash dividend, stock dividend, split, or combination of our common stock. The aggregate number of shares of our common stock available for award under the 2024 Plan will be reduced by one share of our common stock for every one share of its common stock subject to an award granted under the 2024 Plan. Each grant of an award under the 2024 Plan will be evidenced by an award agreement that includes terms and provisions, determined by our Compensation Committee (or other committee of the board of directors designated by the board to administer the 2024 Plan), which outlines the number of shares of common stock, earning or vesting terms, and any other terms consistent with the 2024 Plan.

Employee Stock Purchase Plan

Our Employee Stock Purchase Plan (the "ESPP") became effective immediately prior to the consummation of the IPO. A total of 500,000 shares of our common stock is available for awards under the ESPP and only permits eligible employees to purchase shares of our common stock through payroll deductions, which cannot exceed 10% of the employee's eligible compensation. 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. For the year ended December 31, 2024, we did not recognize any equity-based compensation expense related to the ESPP.

2021 Equity and Incentive Compensation Plan

On January 1, 2021, the BKV Corporation Long-Term Incentive Plan (the "2021 Plan") was established and as of December 31, 2024, 7,724,499 RSUs were considered to have been granted under Accounting Standards Codification ("ASC") 718 - *Compensation-Stock Compensation* ("ASC 718"), 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 December 31, 2024, the awards considered granted under ASC 718 since inception equaled the number of RSUs legally granted.

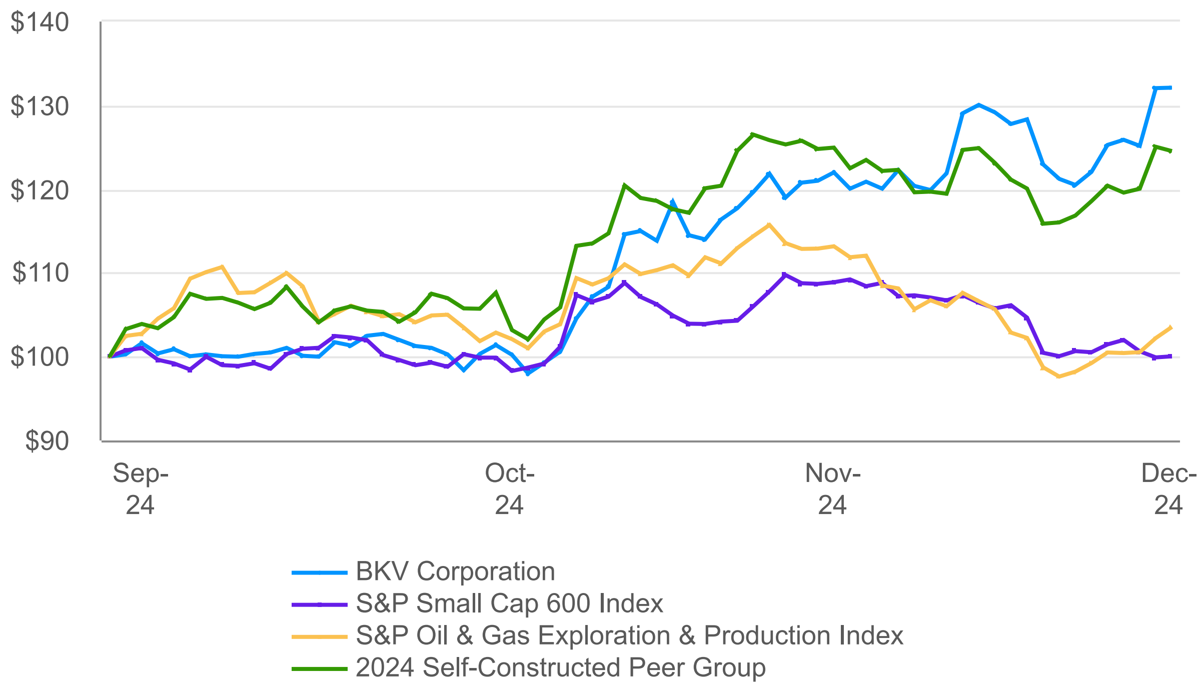
Issuer Purchases of Equity Securities

We currently do not maintain a common stock repurchase program. Any future determination related to a common stock repurchase program 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.

Stock Performance Graph

The following Performance Graph and related information shall not be deemed "soliciting material" or to be "filed" with the Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filings under the Securities Act or the Exchange Act, except to the extent that we specifically incorporate it by reference into such filings.

The performance graph below illustrates changes over the period of September 26, 2024 through December 31, 2024, in cumulative total stockholder return on our common stock as measured against the cumulative total return of the S&P Small Cap 600, the S&P Oil & Gas Exploration and Production Index, and a customized peer group. The graph tracks the performance of a $100 investment in our common stock and in each index (with the reinvestment of all dividends for the index securities) from September 26, 2024 through December 31, 2024.



	9/26/2024	9/30/2024	10/31/2024	11/29/2024	12/31/2024
BKV Corporation	$ 100	$ 102	$ 100	$ 122	$ 132
S&P Small Cap 600	100	101	98	109	100
S&P Oil & Gas Exploration & Production	100	103	102	113	104
2024 Self-Constructed Peer Group [1]	100	104	103	125	125

[1] The 2024 Self-Constructed Peer Group includes the following companies: EQT Corporation, Range Resources Corporation, Gulfport Energy Corporation, Expand Energy Corporation, and CNX Resources Corporation.

ITEM 6. [RESERVED]

ITEM 7. 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 consolidated financial statements and related notes included in Item 8 of Part II, Financial Statements and Supplementary Data in this Annual Report on Form 10-K. This Annual Report on Form 10-K contains certain statements that are forward-looking within the meaning of the Private Securities Litigation Reform Act of 1995. Certain statements contained in the Management's Discussion and Analysis of Financial Condition and Results of Operations are forward-looking statements that involve risks and uncertainties. The forward-looking statements are not historical facts, but rather are based on current expectations, estimates, assumptions, and projections about our industry, business, and future financial results. Our actual results could differ materially from the results contemplated by these forward-looking statements due to a number of factors, including those discussed in other sections of this Annual Report on Form 10-K. See Item 1A of Part I, "Risk Factors" and under "Cautionary Note Regarding Forward-Looking Statements."

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; our natural gas midstream business; power generation; and 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 and third CCUS projects 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.

Recent Developments

Initial Public Offering

- **Initial Public Offering**. On September 27, 2024, we completed our IPO of 15,000,000 shares of common stock at a price to the public of $18.00 per share. After underwriting discounts and commissions of $16.2 million, we received net proceeds from the offering of $253.8 million. We also granted the IPO underwriters a 30-day option to purchase up to 2,250,000 additional shares of common stock on the same terms. The underwriters partially exercised the option and, on October 28, 2024, purchased 701,003 shares of common stock, resulting in additional net proceeds of $11.9 million, after deducting underwriting discounts and commissions of $0.8 million.

Dispositions

- **Sales of Chaffee and Chelsea Assets**. On June 14, 2024, we sold our wholly-owned subsidiary, Chaffee, which owned a non-operated interest in approximately 9,800 net acres and 116.0 gross (24.2 net) wells and 122 Bcfe of proved reserves in the Marcellus Shale in the Appalachian Basin of NEPA, as well as our interest in the Repsol Oil & Gas operated midstream system, for a purchase price of $106.7 million. On June 28, 2024, our wholly-owned subsidiary, Chelsea, sold certain of its non-operated upstream assets, including its interest in approximately 6,800 net acres and 214.0 gross (15.4 net) wells and 35 Bcfe of proved reserves in NEPA for a purchase price of $25.0 million.

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 in *Liquidity and Capital Resources — Loan Agreements and Credit Facilities* below) were paid off with proceeds from the loans under the RBL Credit Agreement (as defined below) 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 "*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 and BKV Upstream Midstream entered into a reserve-based lending agreement (the "RBL Credit Agreement"), with Citibank, N.A. as administrative agent and

the financial institutions party thereto, and with BKV Corporation as the guarantor and BKV Upstream Midstream as the borrower. The RBL Credit Agreement has a maximum credit commitment of $1.5 billion. As of December 31, 2024, the RBL Credit Agreement had an outstanding balance of $165.0 million, a borrowing base of $750.0 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. See "*Liquidity and Capital Resources — Loan Agreements and Credit Facilities*" for additional information regarding the RBL Credit Agreement and the covenants contained therein.

Operational and Financial Highlights

Below are some highlights of our operating and financial results for the year ended December 31, 2024.

- Production of natural gas, NGLs, and oil was 288.4 Bcfe.
- Average realized product prices, excluding the impact of settled derivatives, were $1.93 per Mcfe.
- Production revenues were $557.6 million and midstream revenues were $12.6 million.
- Lease operating expense was $132.3 million, or $0.46 per Mcfe.
- Net income (loss) was $(142.9) million.
- Net cash provided by operating activities was $118.5 million.
- Accrued capital expenditures were $117.6 million.

Factors That Affect Comparability of Our Financial Condition and Results of Operations

Our business depends on many factors, primarily commodity prices, market supply and demand for natural gas, NGLs, and oil, upstream capital costs, and production costs. We continually monitor domestic and global factors which may cause our actual results of operations to differ from historical results or expected outlook.

Commodity Pricing. The natural gas and NGL industry is cyclical and commodity prices are highly volatile, and we expect these prices to continue to remain volatile in the near future. In order to manage our market exposure of price volatility, we utilize derivative contracts in connection with our natural gas operations to provide an economic hedge of our exposure to commodity price risks associated with anticipated future natural gas and NGL production. However, there are still market risks beyond our control that may impact our financial condition, results of operations, and cash flows.

Supply, demand, market risk, and the impact on natural gas, NGLs, and oil prices. 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.

Upstream Capital Costs. 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.

Production Volumes.

The following table presents our historical production volumes for the periods presented:

	Year Ended December 31,		
	2024	2023	2022
Production Data			
Natural gas (MMcf)	228,682	249,766	217,585
NGLs (MBbls)	9,858	10,554	10,187
Oil (MBbls)	96	119	140
Total volumes (MMcfe)	288,406	313,804	279,547
Average daily total volumes (MMcfe/d)	788.0	859.7	765.9

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.

Realized Commodity Prices

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. For further discussion on our derivative contracts, see *Note 7 - Derivative Instruments* in Item 8 of Part II, "*Financial Statements and Supplementary Data.*" The following is a comparison of average pricing excluding and including the effects of derivatives:

	Year Ended December 31,		
	2024	2023	2022
Average prices:			
Natural gas ($/Mcf):			
Average NYMEX Henry Hub price	$ 2.27	$ 2.74	$ 6.64
Average natural gas realized price (excluding derivatives)	$ 1.69	$ 2.04	$ 6.02
Average natural gas realized price (including derivatives) (1)	$ 2.10	$ 2.23	$ 3.72
Differential	$ (0.58)	$ (0.70)	$ (0.62)
NGLs ($/Bbl):			
Average NGL realized price (excluding derivatives)	$ 16.79	$ 17.80	$ 30.58
Average NGL realized price (including derivatives) (1)	$ 17.19	$ 17.55	$ 27.78
Oil ($/Bbl):			
Average oil realized price	$ 68.81	$ 70.97	$ 84.76
High and low daily spot prices:			
Oil ($/Bbl):			
High NYMEX WTI	$ 87.69	$ 93.67	$ 123.64
Low NYMEX WTI	$ 66.73	$ 66.61	$ 71.05
Natural gas ($/Mcf):			
High NYMEX Henry Hub	$ 13.20	$ 3.78	$ 9.85
Low NYMEX Henry Hub	$ 1.21	$ 1.74	$ 3.46

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

Results of Operations

Comparison of the Year Ended December 31, 2024 and 2023

Operating Revenues and Operating Income

Our operating revenues and other income from operations include the activity from the sale of natural gas, NGLs, and oil, midstream revenues, gains and losses on our derivative contracts and on the sales of our business and assets, marketing revenues, related party revenues, and other income from operations. The following table provides information on our revenues and other operating income for the periods presented:

	Year Ended December 31,			
(in thousands, other than percentages)	**2024**	**2023**	**$ Change**	**% Change**
Revenues				
Natural gas revenues	$ 385,456	$ 509,846	$ (124,390)	(24)%
NGL revenues	165,508	187,860	(22,352)	(12)%
Oil revenues	6,606	8,445	(1,839)	(22)%
Midstream revenues	12,560	16,168	(3,608)	(22)%
Derivative gains (losses), net	(34,152)	238,743	(272,895)	*
Marketing revenues	10,668	8,710	1,958	22 %
Gain on sale of business	7,080	—	7,080	*
Gain on sales of assets	3,523	2,207	1,316	60 %
Related party revenues	17,101	4,294	12,807	*
Other	6,631	3,957	2,674	68 %
Total revenues and other operating income	$ 580,981	$ 980,230		
**Percentage not meaningful*				

Natural Gas Revenues

Our natural gas revenues decreased by approximately $124.4 million, or 24%, to $385.5 million for the year ended December 31, 2024, from $509.8 million for the year ended December 31, 2023. The impact of commodity price decreases, excluding the effect of derivative settlements, provided a $81.4 million decrease in year-over-year revenues (calculated as the change in the year-over-year average price times current year's production volumes). The decrease was also due to lower production volumes during the year ended December 31, 2024, primarily from the assets from the Exxon Barnett Acquisition, and from the sale of Chaffee and certain non-operated assets held by Chelsea, which collectively accounted for a $43.0 million decrease in year-over-year revenues (calculated as the change in year-over-year volumes times the prior year's average price).

NGL Revenues

Our NGL revenues decreased by approximately $22.4 million, or 12%, to $165.5 million for the year ended December 31, 2024, from $187.9 million for the year ended December 31, 2023. The decrease was due to lower production volumes during the year ended December 31, 2024, which accounted for a $12.4 million decrease in year-over-year revenues (calculated as the change in year-over-year volumes times the prior year's average price). The decrease was also due to the impact of commodity price decreases, excluding the effect of derivative settlements, which accounted for a $10.0 million decrease in year-over-year revenues (calculated as the change in the year-over-year average price times current year's production volumes).

Oil Revenues

Our oil revenues decreased by approximately $1.8 million, or 22%, to $6.6 million for the year ended December 31, 2024, from $8.4 million for the year ended December 31, 2023. The decrease was due to lower production volumes during the year ended December 31, 2024, which accounted for a $1.6 million decrease in year-over-year revenues (calculated as the change in year-over-year volumes times the prior year's average price). The decrease was also due to the impact of commodity price decreases, excluding the impact of derivative settlements, which account for a $0.2 million decrease in the year-over-year revenues (calculated as the change in the year-over-year average price times current year's production volumes).

Midstream Revenues

Our midstream revenues decreased by approximately $3.6 million, or 22%, to $12.6 million for the year ended December 31, 2024, from $16.2 million for the year ended December 31, 2023. This decrease was primarily due to the divestiture of Chaffee of $2.6 million as we sold our Repsol Midstream Interest in connection with this sale. The remainder of the decrease was due to changes in deal structures that reduced midstream transportation revenue while increasing third party gas sales.

Derivative Gains (Losses), Net

For the year ended December 31, 2024, we had net realized and unrealized losses on derivative contracts of $34.2 million compared to net realized and unrealized gains on derivative contracts of $238.7 million for the year ended December 31, 2023. The decreased losses for the year ended December 31, 2024 was primarily attributable to the significant asset positions as of December 31, 2023 reversing due to settlement during 2024, resulting in unrealized losses of $146.7 million, which included the sale of call options in January 2024 limiting our 2026/2027 pricing upside, and is currently in a long term liability position. The year ended December 31, 2023 resulted in unrealized gains of $148.6 million, due to significant liability positions as of December 31, 2022 that reversed and settled during 2023. This was offset by higher realized gains during the year ended December 31, 2024 compared to the year ended December 31, 2023 of $22.3 million due to slightly lower natural gas prices.

Marketing Revenues

Our marketing revenues increased by approximately $2.0 million to $10.7 million for the year ended December 31, 2024 from $8.7 million for the year ended December 31, 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 year ended December 31, 2024 was primarily due to colder than normal weather in NEPA for the month of January 2024.

Gain on Sale of Business

For the year ended December 31, 2024, we sold our wholly-owned subsidiary, Chaffee, for $104.4 million, net of third party transaction costs. The assets sold had an approximate carrying value of $97.3 million, which resulted in a gain on the sale of Chaffee of $7.1 million.

Gains on Sales of Assets

For the year ended December 31, 2024, we sold other properties for $5.0 million in proceeds, which resulted in a gain on the sale of these properties of $3.6 million. For the year ended December 31, 2023, we sold land and our solar assets for $6.7 million in proceeds, which resulted in a gain on sale of assets of $2.2 million.

Related Party Revenues

We generate a portion of our revenues from a management fee from BKV-BPP Power, the sale of third-party natural gas, and CCUS revenues generated from Section 45Q tax credits. Our related party revenues were $17.1 million for the year ended December 31, 2024 compared to $4.3 million for the year ended December 31, 2023. Related party revenues increased during the year ended December 31, 2024 compared to the year ended December 31, 2023 primarily due to an increase in Section 45Q tax credits of $13.3 million from the injection of CO_2 waste in our Barnett Zero well, which started in the fourth quarter of 2023. This was offset by a decrease in operating fee income with BKV-BPP Power of $0.5 million due to contracted rate decreases.

Other Revenue

We generate a portion of our revenues from the sale of third-party natural gas. Other revenues was $6.6 million for the year ended December 31, 2024 compared to $4.0 million for the year ended December 31, 2023. The increase year-over-year was primarily due to an increase in third party gas sales of $2.7 million.

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, 2024	2023	$ Change	% Change
Operating expenses				
Lease operating and workover	$ 136,991	$ 150,647	$ (13,656)	(9)%
Taxes other than income	35,009	72,290	(37,281)	(52)%
Gathering and transportation costs	222,391	248,990	(26,599)	(11)%
Depreciation, depletion, amortization, and accretion	217,533	223,370	(5,837)	(3)%
General and administrative	104,473	114,688	(10,215)	(9)%
Other	19,385	12,625	6,760	54 %
Total operating expense	$ 735,782	$ 822,610		
Average costs per Mcfe				
Lease operating and workover	$ 0.47	$ 0.48	$ (0.01)	(2)%
Taxes other than income	0.12	0.23	(0.11)	(48)%
Gathering and transportation costs	0.77	0.79	(0.02)	(3)%
Depreciation, depletion, amortization, and accretion	0.75	0.71	0.04	6 %
General and administrative	0.36	0.37	(0.01)	(3)%
Other	0.07	0.04	0.03	75 %
Total	$ 2.54	$ 2.62		
**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, 2024		2023		$ Change	% Change
(in thousands, other than percentages and average costs)	Amount	Per Mcfe	Amount	Per Mcfe		
Lease operating expenses	$ 132,317	$ 0.46	$ 142,911	$ 0.46	$ (10,594)	(7)%
Workover expenses	4,674	0.01	7,736	0.02	(3,062)	(40)%
Total lease operating and workover expense	$ 136,991	$ 0.47	$ 150,647	$ 0.48	$ (13,656)	(9)%

Lease operating and workover expenses were $137.0 million, or $0.47 per Mcfe, for the year ended December 31, 2024, which was a decrease of approximately $13.7 million, or 9%, from $150.6 million, or $0.48 per Mcfe, for the year ended December 31, 2023. The decrease in lease operating and workover expenses during the year ended December 31, 2024 compared to the same period in 2023 was due to decreases in compression and water expenses of $5.6 million, materials and labor of $3.6 million, and repairs and maintenance of $2.7 million, all of which were due to cost savings initiatives that began during the second half of 2023 and the divestiture of Chaffee and certain non-operating upstream assets in Chelsea. In addition, during the year ended December 31, 2024, we received a credit of $1.5 million for a water sharing agreement that related to 2023.

Taxes Other Than Income

Taxes other than income were $35.0 million, or $0.12 per Mcfe, for the year ended December 31, 2024, which was a decrease of approximately $37.3 million, or 52%, from $72.3 million, or $0.23 per Mcfe, for the year ended December 31, 2023. The decrease in taxes other than income during the year ended December 31, 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 $27.8 million and $9.2 million, respectively. Certain ad valorem and production taxes are not applicable to our NEPA properties.

Gathering and Transportation

Gathering and transportation expenses were $222.4 million, or $0.77 per Mcfe, for the year ended December 31, 2024, which was a decrease of approximately $26.6 million, or 11%, from $249.0 million, or $0.79 per Mcfe, for the year ended December 31, 2023. This decrease was driven by decreased production in the Barnett and natural gas rate decreases of $15.7 million and $12.2 million, respectively. This was offset by new contracts we entered into during 2024 where we started outsourcing gathering costs with our midstream business of $1.3 million.

Depreciation, Depletion, Amortization, and Accretion

Depreciation, depletion, amortization, and accretion was $217.5 million, or $0.75 per Mcfe, for the year ended December 31, 2024, which was a decrease of approximately $5.8 million, or 3%, from $223.4 million, or $0.71 per Mcfe, for the year ended December 31, 2023. The decrease in depreciation, depletion, amortization, and accretion during the year ended December 31, 2024 compared to the year ended December 31, 2023 was due to lower production during the year ended December 31, 2024 compared to the same period in the prior year, offset by lower estimated proved reserves resulting from lower natural gas prices used in the determination of proved reserves and from the divestiture of Chaffee and certain non-operated upstream assets in Chelsea in June 2024.

General and Administrative

General and administrative expenses were $104.5 million, or $0.36 per Mcfe, for the year ended December 31, 2024, which was a decrease of approximately $10.2 million, or 9%, from $114.7 million, or $0.37 per Mcfe, for the year ended December 31, 2023. The decrease was driven by a $22.2 million reduction in equity-based compensation related to the expiration of performance-based restricted stock units (“PRSU”) on December 31, 2023, and an $8.0 million decrease in management fees following the termination of the Verde CO2 contract in November 2023. These cost savings were partially offset by a $12.6 million acceleration of time-based restricted stock units (“TRSU”) recognized upon the IPO (including $2.5 million in payroll taxes), $3.5 million in stock compensation expense under the 2024 Plan, and $3.7 million in higher payroll costs due to increased headcount in 2024.

Other Operating Expenses

Other operating expenses were $19.4 million, or $0.07 per Mcfe, for the year ended December 31, 2024, which was an increase of approximately $6.8 million, or 54%, from $12.6 million, or 0.04 per Mcfe, for the year ended December 31, 2023. The increase in other operating expenses during the year ended December 31, 2024 compared to the same period in 2023 was primarily driven by the following factors: $5.3 million in CCUS operating expenses for CO_2 purchases and fuel and increased legal contingencies, $3.4 million in higher emissions monitoring costs, $2.1 million in well clean up costs and expenses related to a potential CCUS equity raise and investments, and $1.0 million in costs from the newly enacted EPA fees under the Inflation Reduction Act. These increases were offset by $3.6 million of inventory restocking and rig termination fees, $2.0 million of prior year inventory restocking fees and write-offs, and $0.7 million of lower midstream operating expenses and gas purchases.

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 $9.7 million, for the year ended December 31, 2024, which was a decrease of approximately $28.7 million from the $38.4 million gain for the year ended December 31, 2023. The $9.7 million gain compared to the $38.4 million gain was primarily attributable to the prior period’s gain on contingent consideration liabilities with the Devon Barnett Acquisition of $25.0 million compared to the current period's gain of $7.5 million, as well as the prior period's gain on contingent consideration liabilities with the Exxon Barnett Acquisition of $13.4 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 year ended December 31, 2023 compared to slight decreases during the year ended December 31, 2024.

Earnings (losses) from equity affiliate. Earnings from our equity affiliate was $10.4 million for the year ended December 31, 2024, which was a decrease of $6.4 million, from $16.9 million compared to the year ended December 31, 2023. 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.

Loss on early extinguishment of debt. Loss on early extinguishment of debt was $13.9 million for the year ended December 31, 2024 in connection with the early termination of our Term Loan Credit Facility and Revolving Credit Agreement that took place in June 2024.

Interest expense. Interest expense was $45.6 million for the year ended December 31, 2024, which was a decrease of $24.4 million, from $69.9 million for the year ended December 31, 2023. The decrease in interest expense during the year ended December 31, 2024 was primarily due to lower interest rates on our RBL Credit Facility, which we entered into on June 11, 2024, and the subsequent pay down on the outstanding balances on our SCB Credit Facility, the Revolving Credit Agreement, and the Term Loan Credit Agreement, which incurred higher interest rates.

Interest expense, related party. Interest expense from our related party was $5.2 million for the year ended December 31, 2024, which was a decrease of $1.9 million, from $7.1 million for the year ended December 31, 2023. The decrease was due to the pay down of $75.0 million of related party borrowings with BNAC during the year ended December 31, 2024, slightly offset by the increase in interest rates year-over-year.

Income tax benefit (expense). For the year ended December 31, 2024, we had an income tax benefit of $43.6 million, which was a change of $71.8 million, from an income tax expense of $28.2 million for the year ended December 31, 2023. The year-over-year change was primarily due to a pre-tax loss for the year ended December 31, 2024 compared to a pre-tax income for the year ended December 31, 2023. During the year ended December 31, 2024, we also recognized additional income tax expense due to executive compensation disallowance, which was offset by a tax benefit from the monetization of Section 45Q tax credits associated with the injection of CO_2 waste in the Barnett Zero Project, Code Section 45I Marginal Well Credits from marginal production, excess tax benefits relating to the vesting of restricted shares, and by state apportionment changes due to the sale of Chaffee.

Results of Operations

Comparison of the Year Ended December 31, 2023 and 2022

Operating Revenues and Operating Income

Our operating revenues and other income from operations include the activity from the sale of natural gas, NGLs, and oil, midstream revenues, gains and losses on our derivative contracts and on the sale of assets, marketing revenues, and other income from operations. The following table provides information on our revenues and other operating income 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)%
Gain on sales of assets	2,207	—	2,207	*
Related party revenues	4,294	2,682	1,612	60 %
Other	3,957	117	3,840	*
Total revenues and other operating income	$ 980,230	$ 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-over-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-over-year volumes times the prior year average price).

NGL Revenues

Our NGL revenues decreased by approximately $123.7 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 $134.9 million decrease in year-over-year revenues (calculated as the change in the year-over-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-over-year volumes times the prior year average price).

Oil Revenues

Our oil revenues decreased by approximately $3.4 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 $1.8 million decrease in year-over-year revenues (calculated as the change in year-over-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-over-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 gains 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 Revenues

We generate a portion of our revenues from a management fee from the BKV-BPP Power Joint Venture. Our related party revenues were $4.3 million for the year ended December 31, 2023, as compared to $2.7 million for the year ended December 31, 2022. Related party revenues increased during the year ended December 31, 2023 compared to the year ended December 31, 2023 primarily due to an increase in operating fee income with BKV-BPP Power of $0.9 million due to contracted rate increases and Section 45Q tax credits of $0.7 million from the injection of CO_2 waste in our Barnett Zero well, which started in the fourth quarter of 2023.

Other Revenue

Other revenues were $4.0 million for the year ended December 31, 2023, as compared to $0.1 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	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 costs	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 expense	$ 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 costs	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:

	Year Ended December 31, 2023		2022		$ Change	% Change
(in thousands, other than percentages and average costs)	Amount	Per Mcfe	Amount	Per Mcfe		
Lease operating expenses	$ 142,911	$ 0.46	$ 123,386	$ 0.44	$ 19,525	16 %
Workover expenses	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 %

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 $9.0 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 $31.7 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 related party loan with BNAC, which provided for seven months of interest in 2022 compared to a full year in 2023.

Other income. Other income was $6.2 million for the year ended December 31, 2023, which was an increase of $4.8 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 and the sale of surface rights of $1.1 million during the year ended December 31, 2023.

Income tax expense. Income tax expense was $28.2 million for the year ended December 31, 2023, which was a decrease of $34.4 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.

Liquidity and Capital Resources

Capital Commitments

Our primary needs for cash are to fund our upstream development, midstream, power, and CCUS activities, fund operations and capital expenditures, acquisitions and asset retirement obligations, cover any debt interest or minimum volume commitment obligations, pay down debt, and return capital to stockholders. Our primary uses of cash during the years ended December 31, 2024 and 2023 were to pay down debt and fund the development of our natural gas properties, and during the year ended December 31, 2022, our primary use of cash was to fund our Exxon Barnett Acquisition.

During the years ended December 31, 2024, 2023, and 2022, cash paid for capital expenditures was $100.9 million, $187.7 million, and $248.1 million, respectively. Our current estimated budget for total capital expenditures in 2025 is approximately $320 million to $380 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.

Capital Resources

Historically, our primary sources of capital and liquidity have consisted of internally generated cash flows from operations, together with loans and capital contributions from our majority stockholder, BNAC. We also enter into financial instruments to reduce the impact of commodity price volatility and provide a level of certainty and stability around of cash flows. We currently believe that our cash flows from operations, cash on hand, borrowings under our RBL Credit Agreement, and our commodity hedges in place will provide sufficient liquidity to fund our operations and our capital expenditures into 2025, excluding our CCUS business. 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, debt financing, and federal grants with the remaining capital needs being funded with cash flows from operations. We are currently in non-binding exclusive discussions concerning a potential joint venture with a third-party investor with the expectation to close in the first half of 2025. We are targeting completion of third-party CCUS financing in 2025; however, there can be no assurance that we will be able to complete any CCUS financing on our targeted timeline or at all.

The following table summarizes our cash flows for the years ended December 31, 2024, 2023, and 2022 (in thousands):

	Year Ended December 31,		
	2024	2023	2022
Net cash provided by operating activities	$ 118,538	$ 123,076	$ 349,194
Net cash provided by (used in) investing activities	36,066	(177,848)	(865,566)
Net cash provided by (used in) financing activities	(304,805)	66,713	534,833
Net increase (decrease) in cash, cash equivalents, and restricted cash	$ (150,201)	$ 11,941	$ 18,461

Cash flows provided by operating activities. Net cash provided by operating activities was $118.5 million for the year ended December 31, 2024, compared to $123.1 million for the year ended December 31, 2023. Net cash provided by operating activities decreased during the year ended December 31, 2024 compared to the year ended December 31, 2023 due to a $41.5 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 $17.3 million decrease in working capital, $10.0 million in distributions from the BKV-BPP Power Joint Venture made in 2023, and $3.9 million of transaction costs associated with the sale of Chaffee and certain non-operated upstream assets in Chelsea. These decreases were offset by reduced settlements of contingent liabilities of $45.0 million and cash received from the sale of call options of $23.5 million.

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.

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 $36.1 million for the year ended December 31, 2024, compared to net cash used in investing activities of $177.8 million for the year ended December 31, 2023. Contributing to the cash inflow during the year ended December 31, 2024 were the total proceeds from the sale of Chaffee and certain non-operated upstream assets held by Chelsea of $132.6 million. The change was also due to the decrease of $49.0 million of capital expenditures (excluding CCUS activities), a $37.8 million reduction of CCUS-related expenditures, and a $4.9 million decrease in cash used for acquisition of natural gas properties for the year ended December 31, 2024 compared to the prior year. This was offset by a reduction of $10.4 million of cash proceeds from other investing activities for the year ended December 31, 2024 compared to the prior year.

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.

The following table presents our capital expenditures (excluding leasehold costs and acquisitions) on an accrual basis for the years ended December 31, 2024, 2023, and 2022 and reconciles to cash flows used for capital expenditures in the consolidated statements of cash flows.

	Year Ended December 31,		
	2024	2023	2022
		(in thousands)	
Total use of cash and cash equivalents for capital expenditures	$ (100,916)	$ (187,716)	$ (248,097)
(Increase) decrease in accrued capital expenditures	(16,710)	23,863	(19,247)
Capital expenditures (accrued)	$ (117,626)	$ (163,853)	$ (267,344)

Cash flows provided by (used in) financing activities. Net cash used in financing activities was $304.8 million for the year ended December 31, 2024, which consisted of net payments on debt of $493.0 million, payments of $53.2 million for taxes related to net share settlement of restricted stock units, and payments of debt issuance costs and debt extinguishment costs of $18.3 million. This was offset by net proceeds from the issuance of common stock from our IPO of $265.7 million, after deducting underwriting discounts and commissions.

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 the Term Loan Credit Agreement and proceeds of $75.0 million in connection with the related party note payable with BNAC, offset by repayments of $166.0 million to the related party, $190.0 million of advances received in connection with our Overseas Chinese Banking Corporation 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.

Working Capital

As of December 31, 2024, we had cash and cash equivalents of $14.9 million, compared to $25.4 million of cash and cash equivalents, and restricted cash of $139.7 million as of December 31, 2023. Our net working capital deficit was $71.6 million as of December 31, 2024, compared to a deficit of $100.1 million as of December 31, 2023.

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. Furthermore, we expect that our pace of development, production volumes, commodity prices, and differentials to NYMEX pricing for our natural gas and oil production will be the largest variables impacting our working capital.

Loan Agreements and Credit Facilities

Term Loan Credit Agreement

On June 16, 2022, we entered into 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.

RBL Credit Agreement

On June 11, 2024, BKV Corporation, as guarantor, and BKV Upstream Midstream, 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 December 31, 2024, the RBL Credit Agreement had a borrowing base of $750.0 million and an elected commitment of $600.0 million. As of March 31, 2025, $200.0 million of revolving borrowings and $14.1 million of letters of credit were outstanding under the RBL Credit Agreement, leaving $385.9 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, BKV Upstream Midstream, and all of BKV Upstream Midstream'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 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 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 BKV Upstream Midstream 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 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 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, BKV Upstream Midstream, and its restricted subsidiaries that are guarantors, and upon an event of default the agent under the RBL Credit Agreement could commence foreclosure proceedings.

Revolving Credit Agreements

On June 11, 2024, using the funds from the RBL Credit Agreement, we repaid the outstanding debt balances under (i) the Term Loan Credit Agreement, (ii) the Revolving Credit Agreement, and (iii) our loan agreement previously entered into in March 2022 with Standard Charter Bank (the "SCB Credit Facility"), in each case 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.

BKV-BPP Power and BKV-BPP Cotton Cove Joint Ventures

Under the terms of the BKV-BPP Power LLC Agreement and BKV-BPP Cotton Cove 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, 2024, no distributions were made by BKV-BPP Power or BKV-BPP Cotton Cove. During the year ended December 31, 2023, BKV-BPP Power made a distribution of $10.0 million to BKV Corporation, and during the year ended December 31, 2022, 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 BKV-BPP Power must be approved by a majority of BKV-BPP Power's ten member board of managers, five of whom are appointed by us and five of whom are appointed by BPPUS. Similarly, any additional capital contributions to BKV-BPP Cotton Cove must receive the unanimous approval of BKV-BPP Cotton Cove, LLC's six member board of managers, four of whom are appointed by us and two of whom are appointed by BPPUS. For more information about our joint ventures with BPPUS, 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. 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 may 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.

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 December 31, 2024, our material off-balance sheet arrangements and transactions included volume commitments of $320.6 million and letters of credit of $14.1 million against the RBL Credit Agreement. For further information regarding these arrangements, see *Note 16 - Commitments and Contingencies* to our consolidated financial statements 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. For more information, see Item 8 of Part II, *Financial Statements and Supplementary Data, Note 2 - Summary of Significant Accounting Policies.*

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.

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 2 - Summary of Significant Accounting Policies* to our consolidated financial statements included in this Annual Report on Form 10-K 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.

Emerging Growth Company Status

We are an "emerging growth company" as defined under 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. We have elected to take advantage of certain of the reduced disclosure obligations in this Annual Report on Form 10-K and may elect to take advantage of other reduced reporting requirements in our future filings with the SEC. As a result, the information that we provide to our stockholders may be different from other public reporting companies.

Under the JOBS Act, emerging growth companies can delay adopting new or revised accounting standards issued subsequent to the enactment of the JOBS Act, until such time as those standards apply to private companies. However, 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 our IPO. 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.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES 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 NGL 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 NGL production when management believes that favorable future prices can be secured.

Our financial hedging activities are intended to support natural gas and NGL prices at targeted levels and to manage our exposure to natural gas and NGL 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, 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 December 31, 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 December 31, 2024 is summarized in "*Note 7 - Derivative Instruments*" to our consolidated financial statements.

We may enter into single hedge transactions with settlements up to 48 months. The aggregation of these executed hedge instruments may not exceed 60% without board of director approval 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 years ended December 31, 2024, 2023, and 2022, a hypothetical increase or decrease of $0.10 per Mcf in NYMEX would have resulted in a $9.7 million, $1.6 million, and $7.7 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 $7.0 million, $1.9 million, and $4.6 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 BKV-BPP Power, 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 BKV-BPP Power, 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 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 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 December 31, 2024, the estimated fair value of our commodity derivative instruments was a net liability of $67.6 million, comprised of current 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.

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.

Interest Rate Risks

As of December 31, 2024, our primary exposure to interest rate risk resulted from our $165.0 million of outstanding borrowings on our RBL Credit Agreement, which has a floating interest rate. 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, all of which had 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 years ended December 31, 2024 and 2023 was approximately 9.3% and 8.7%, respectively. We estimate that a 1.0% increase in the applicable average interest rates during the years ended December 31, 2024 and 2023 would have resulted in increases of $4.9 million and $7.8 million in interest expense, respectively.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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, 2024 and 2023, and the related consolidated statements of operations, of stockholders' equity and mezzanine equity and of cash flows for each of the three years in the period ended December 31, 2024, 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, 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2024 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
March 31, 2025
We have served as the Company's auditor since 2020.

BKV CORPORATION
CONSOLIDATED BALANCE SHEETS

(in thousands, except per share amounts)

Table of Contents

	December 31,	
	2024	2023
Assets		
Current assets		
Cash and cash equivalents	$ 14,868	$ 25,407
Restricted cash	—	139,662
Accounts receivable, net	50,478	48,500
Accounts receivable, related parties	15,371	559
Prepaid expenses	7,638	3,837
Inventory	6,255	9,935
Commodity derivative assets, current	—	84,039
Other current assets	—	218
Total current assets	94,610	312,157
Natural gas properties and equipment		
Developed properties	2,315,167	2,370,156
Undeveloped properties	10,757	15,846
Midstream assets	276,644	318,855
Accumulated depreciation, depletion, and amortization	(714,287)	(579,415)
Total natural gas properties, net	1,888,281	2,125,442
Other property and equipment, net	97,300	83,935
Goodwill	18,417	18,417
Investment in joint venture	115,173	104,750
Commodity derivative assets	—	18,508
Other noncurrent assets	17,307	19,937
Total assets	$ 2,231,088	$ 2,683,146
Liabilities, mezzanine equity, and stockholders' equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 121,366	$ 149,173
Contingent consideration payable	20,000	20,000
Commodity derivative liabilities, current	20,277	—
Income taxes payable to related party	1,438	864
Credit facilities	—	127,000
Current portion of long-term debt, net	—	112,373
Other current liabilities	3,124	2,849
Total current liabilities	166,205	412,259
Asset retirement obligations	198,795	193,205
Contingent consideration	—	29,676
Commodity derivative liabilities	47,357	—
Note payable to related party	—	75,000
Deferred tax liability, net	88,688	143,968
Long-term debt, net	165,000	339,663
Other noncurrent liabilities	5,469	11,652
Total liabilities	671,514	1,205,423
Commitments and contingencies (Note 16)		
Mezzanine equity		
Common stock - minority ownership puttable shares; 0 and 2,403 authorized shares as of December 31, 2024 and 2023, respectively; and 0 and 2,403 shares issued and outstanding as of December 31, 2024 and 2023, respectively	—	59,988
Equity-based compensation	—	126,966
Total mezzanine equity	—	186,954
Stockholders' equity		
Common stock, $0.01 par value; 300,000 authorized shares; 84,600 and 63,873 shares issued and outstanding as of December 31, 2024 and 2023, respectively	1,512	1,283

Treasury stock, shares at cost; 214 shares and 213 shares as of December 31, 2024 and 2023, respectively	(6,663)	(4,582)
Additional paid-in capital	1,447,671	1,034,144
Retained earnings	117,054	259,924
Total stockholders' equity	1,559,574	1,290,769
Total liabilities, mezzanine equity, and stockholders' equity	$ 2,231,088	$ 2,683,146

BKV CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per share amounts)

Table of Contents

	For the Year Ended December 31,		
	2024	**2023**	**2022**
Revenues and other operating income			
Natural gas, NGL, and oil sales	$ 557,570	$ 706,151	$ 1,633,747
Midstream revenues	12,560	16,168	12,676
Derivative gains (losses), net	(34,152)	238,743	(629,701)
Marketing revenues	10,668	8,710	11,001
Gain on sale of business	7,080	—	—
Gains on sales of assets	3,523	2,207	—
Related party revenues	17,101	4,294	2,682
Other	6,631	3,957	117
Total revenues and other operating income	580,981	980,230	1,030,522
Operating expenses			
Lease operating and workover	136,991	150,647	131,497
Taxes other than income	35,009	72,290	114,668
Gathering and transportation	222,391	248,990	208,758
Depreciation, depletion, amortization, and accretion	217,533	223,370	118,909
General and administrative	104,473	114,688	148,559
Other	19,385	12,625	3,567
Total operating expenses	735,782	822,610	725,958
Income (loss) from operations	(154,801)	157,620	304,564
Other income (expense)			
Bargain purchase gain	—	—	170,853
Gain on settlement of litigation	—	—	16,866
Gains on contingent consideration liabilities	9,676	38,375	6,632
Earnings from equity affiliate	10,423	16,865	8,493
Loss on early extinguishment of debt	(13,877)	—	—
Interest expense	(45,582)	(69,942)	(26,322)
Interest expense, related party	(5,181)	(7,078)	(10,846)
Interest income	3,859	3,138	1,143
Other income	9,008	6,165	1,411
Income (loss) before income taxes	(186,475)	145,143	472,794
Income tax benefit (expense)	43,605	(28,225)	(62,652)
Net income (loss)	$ (142,870)	$ 116,918	$ 410,142
Net income (loss) per common share:			
Basic	$ (2.00)	$ 1.93	$ 6.99
Diluted	$ (2.00)	$ 1.82	$ 6.62
Weighted average number of common shares outstanding:			
Basic	71,288	60,730	58,659
Diluted	71,288	64,380	61,990

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

BKV CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

Table of Contents

	Year Ended December 31,		
	2024	2023	2022
Cash flows from operating activities:			
Net income (loss)	$ (142,870)	$ 116,918	$ 410,142
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depreciation, depletion, amortization, and accretion	217,892	224,427	130,038
Equity-based compensation expense	16,316	25,756	31,947
Deferred income tax (benefit) expense	(44,811)	32,394	89,065
Unrealized (gains) losses on derivatives, net	146,679	(148,564)	(58,815)
Gains on contingent consideration liabilities	(9,676)	(38,375)	(6,632)
Settlement of contingent consideration	(20,000)	(65,000)	(45,300)
Proceeds from the sale of call options	23,502	—	—
Gain on bargain purchase	—	—	(170,853)
Gain on sale of business	(7,080)	—	—
Gains on sale of assets	(3,523)	(2,207)	—
Transaction costs from sale of business	(3,461)	—	—
Earnings from equity affiliate	(10,423)	(16,865)	(8,493)
Distribution from equity affiliate	—	10,000	—
Loss on early extinguishment of debt	13,877	—	—
Other, net	(3,874)	3,029	911
Changes in operating assets and liabilities:			
Accounts receivable, net	(4,652)	86,477	(39,394)
Accounts receivable, related party	(14,812)	(143)	3,082
Accounts payable and accrued liabilities	(32,165)	(98,238)	62,539
Other changes in operating assets and liabilities	(2,381)	(6,533)	(49,043)
Net cash provided by operating activities	118,538	123,076	349,194
Cash flows from investing activities:			
Business combination	—	—	(619,437)
Acquisition of natural gas properties	—	(4,889)	—
Capital expenditures	(100,916)	(187,716)	(248,097)
Proceeds from sale of business	132,571	—	—
Proceeds from sales of assets	5,060	6,667	—
Loan advanced to equity affiliate	—	(8,000)	—
Loan repayment from equity affiliate	—	8,000	—
Other investing activities, net	(649)	8,090	1,968
Net cash provided by (used in) investing activities	36,066	(177,848)	(865,566)
Cash flows from financing activities:			
Proceeds from issuance of common stock in initial public offering, net of underwriting discounts and commissions	265,661	—	—
Proceeds from the issuance of common stock	—	150,005	—
Proceeds from notes payable from related party	—	17,000	75,000
Payments on notes payable to related party	(75,000)	(17,000)	(166,000)
Proceeds under RBL Credit Agreement	580,000	—	—
Payments on RBL Credit Agreement	(415,000)	—	—
Proceeds under term loan agreement	—	—	570,000
Payment on term loan agreement	(456,000)	(114,000)	—
Payment of debt issuance costs	(8,054)	—	(7,738)
Proceeds from draws on credit facilities	44,000	375,500	190,000
Payments on credit facilities	(171,000)	(338,500)	(100,000)
Settlement of contingent consideration	—	—	(19,700)
Payments of deferred offering costs	(3,879)	(2,901)	(5,625)
Debt extinguishment costs	(10,213)	—	—
Net share settlements, equity-based compensation	(53,239)	(2,961)	(1,178)
Other financing activities	(2,081)	(430)	74
Net cash provided by (used in) financing activities	(304,805)	66,713	534,833

Net increase (decrease) in cash, cash equivalents, and restricted cash	(150,201)	11,941	18,461
Cash, cash equivalents, and restricted cash, beginning of period	165,069	153,128	134,667
Cash, cash equivalents, and restricted cash, end of period	$ 14,868	$ 165,069	$ 153,128

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

(in thousands)

Table of Contents

Supplemental cash flow information:	Year Ended December 31, 2024	2023	2022
Cash payments for:			
Interest	$ 60,492	$ 68,480	$ 32,086
Income tax	6	1,545	400
Non-cash investing and financing activities:			
Conversion of mezzanine equity to common stock upon initial public offering	42,995	—	—
Conversion of equity-based compensation to common stock upon initial public offering	74,993	—	—
Income tax deconsolidation	10,469	—	—
Reclassification of deferred offering costs to common stock upon initial public offering	11,649	—	—
Increase (decrease) in accrued capital expenditures	16,710	(23,863)	19,247
Additions to asset retirement obligations	42	89	302
Revisions to asset retirement obligation estimates	—	—	36,516
Lease liabilities arising from obtaining right-of-use assets	494	3,061	1,218
Increase (decrease) in accrued offering costs	(341)	(604)	945
Fair value of contingent consideration from acquisitions	—	—	17,150
Adjustment of minority ownership puttable shares to redemption value	16,989	2,722	12,793
Adjustment of equity-based compensation to redemption value	9,310	15,602	24,400
Impact of redemption of shares issued in settlement of equity-based compensation and other on additional paid-in capital, common stock, and treasury stock	2,081	781	4

BKV CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND MEZZANINE EQUITY
(in thousands)

Table of Contents

	Stockholders' Equity							Mezzanine Equity			
	Common Stock		Treasury		Additional Paid-In Capital	Retained Earnings	Total Stockholders' Equity	Common Stock		Equity-based Compensation	Total Mezzanine Equity
	Shares	Amount	Shares	Amount				Shares	Amount		
Balance, December 31, 2021	56,373	$ 1,132	192	$ (3,970)	$ 933,622	$ (267,136)	$ 663,648	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	—	—	1	(4)	4	—	—	—	—	(4)	(4)
Issuance of common stock from employee stock purchase plan	—	—	—	—	—	—	—	2	78	—	78
Common stock issued upon vesting of RSUs, 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
Balance, December 31, 2022	56,373	$ 1,132	193	$ (3,974)	$ 896,433	$ 143,006	$ 1,036,597	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	20	(604)	736	—	133	(21)	(2)	(602)	(604)
Common stock issued upon vesting of RSUs, 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

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

BKV CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND MEZZANINE EQUITY
(in thousands)

Table of Contents

Balance, December 31, 2023	63,873	$ 1,283	213	$ (4,582)	$ 1,034,144	$ 259,924	$ 1,290,769	2,403	$ 59,988	$ 126,966	$ 186,954
Net loss	—	—	—	—	—	(142,870)	(142,870)	—	—	—	—
Adjustment of minority ownership puttable shares to redemption value	—	—	—	—	16,989	—	16,989	—	(16,989)	—	(16,989)
Adjustment of equity-based compensation to redemption value	—	—	—	—	9,310	—	9,310	—	—	(9,310)	(9,310)
Redemption of common stock issued upon vesting of equity-based compensation	—	1	—	(2,077)	2,076	—	—	(73)	—	(2,077)	(2,077)
Common stock issued upon vesting of RSUs, net of shares withheld for income taxes	—	—	—	—	—	—	—	2,696	—	(53,239)	(53,239)
Redemption of common stock issued from employee stock purchase plan	—	—	1	(4)	4	—	—	—	(4)	—	(4)
Issuance of common stock upon initial public offering, net of offering costs	15,701	157	—	—	253,099	—	253,256	—	—	—	—
Income tax deconsolidation	—	—	—	—	10,469	—	10,469	—	—	—	—
Mezzanine equity conversion	5,026	71	—	—	117,917	—	117,988	(5,026)	(42,995)	(74,993)	(117,988)
Equity-based compensation	—	—	—	—	3,663	—	3,663	—	—	12,653	12,653
Balance, December 31, 2024	84,600	$ 1,512	214	$ (6,663)	$ 1,447,671	$ 117,054	$ 1,559,574	—	$ —	$ —	$ —

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 BNAC. BKV Corp's ultimate parent company is Banpu Public Company Limited, a public company listed in the Stock Exchange of Thailand. As of March 31, 2025, the date these consolidated financial statements were available to be issued, BNAC owned 75.4% of BKV Corp's shares. The remaining 24.6% 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.

Basis of Presentation

The accompanying consolidated financial statements have been prepared in accordance with GAAP and include the accounts for BKV Corp's wholly-owned subsidiaries.

BKV Upstream Midstream, a limited liability company, was formed on May 21, 2024 and is registered in the state of Delaware. This entity is a wholly-owned subsidiary of BKV Corp. Since its formation, all of 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 on June 28, 2024, sold certain of its non-operated upstream assets in BKV Chelsea, LLC ("Chelsea"). See *Note 3 - Acquisition and Dispositions* 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 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.

Business Segment Information

In accordance with Accounting Standards Codification ("ASC") 280 - *Segment Reporting*, the Company is organized, managed, and identified as one operating segment and one reportable segment as the Company does not distinguish between business lines for the purpose of making decisions about resource allocation and performance management. The Company's Chief Executive Officer, identified as the Chief Operating Decision Maker ("CODM"), evaluates financial performance on a consolidated basis, primarily using net income from the consolidated statements of operations. Additionally, the CODM reviews reported consolidated revenues, significant segment expenses, and other segment items as presented on the consolidated statements of operations on a monthly basis to allocate resources, manage liquidity, and assess overall Company performance relative to budget. The CODM also monitors total assets and capital expenditures, on a consolidated basis, as presented on the consolidated balance sheets and consolidated statements of cash flows, respectively.

Revision of Previously Issued Financial Statements

In connection with the preparation of the consolidated financial statements for the year ended December 31, 2024, the Company identified an error in its previously issued consolidated financial statements that originated prior to January 1, 2021. Specifically, in connection with the corporate restructuring of BKV Corp in 2020, the tax basis of certain assets was calculated in error resulting in an understatement of deferred tax liabilities, net of $7.4 million, an understatement of tax expense, and an overstatement of retained earnings.

Management assessed the materiality of this error and concluded it was not material to the Company's previously issued financial statements. Management has revised its previously issued consolidated financial statements to correct the errors as follows (in thousands):

	December 31, 2023		
Consolidated Balance Sheets	**As Previously Reported**	**Adjusted**	**As Revised**
Liabilities, mezzanine equity, and stockholders' equity			
Deferred tax liability, net	$ 136,524	$ 7,444	$ 143,968
Total liabilities	1,197,979	7,444	1,205,423
Retained earnings	267,368	(7,444)	259,924
Total stockholders' equity	1,298,213	(7,444)	1,290,769
Total liabilities, mezzanine equity, and stockholders' equity	$ 2,683,146	$ —	$ 2,683,146

Consolidated Statements of Stockholders' Equity and Mezzanine Equity	As Previously Reported	Adjusted	As Revised
Retained earnings			
Balance, December 31, 2021	$ (259,692)	$ (7,444)	$ (267,136)
Balance, December 31, 2022	150,450	(7,444)	143,006
Balance, December 31, 2023	267,368	(7,444)	259,924
Total stockholders' equity			
Balance, December 31, 2021	671,092	(7,444)	663,648
Balance, December 31, 2022	1,044,041	(7,444)	1,036,597
Balance, December 31, 2023	1,298,213	(7,444)	1,290,769

Reclassification

For the year ended December 31, 2023, a reclassification was made to the consolidated statements of operations for the year ended December 31, 2023 to reclassify the gains on sale of assets out of other income into revenues to conform with the current presentation. Additionally, certain prior year amounts have been reclassified in order to conform to the current year presentation. These reclassifications had no impact on previously reported balance sheets, net income, net cash flows, or stockholders' equity.

Initial Public Offering

On September 27, 2024, the Company completed its initial public offering (the "IPO") of 15,000,000 shares of common stock at a price to the public of $18.00 per share. After underwriting discounts and commissions of $16.2 million, the Company received net proceeds from the offering of $253.8 million. The Company also granted the IPO underwriters a 30-day option to purchase up to 2,250,000 additional shares of common stock on the same terms. The underwriters partially exercised the option and on October 28, 2024, purchased 701,003 additional shares of common stock, resulting in additional net proceeds of $11.9 million, after deducting underwriting discounts and commissions of $0.8 million.

Upon consummation of the IPO, 5,026,638 mezzanine shares were converted into common stock.

Deferred Offering Costs

The Company capitalized legal and other third party fees directly related to the Company's IPO on the consolidated balance sheets, and on September 27, 2024, the Company recognized these costs as a reduction to the proceeds received from the IPO in the amount of $11.6 million.

Liquidity

As of December 31, 2024, the Company held $14.9 million of cash and cash equivalents. The Company's working capital deficit as of December 31, 2024 was $71.6 million, and for the year ended December 31, 2024, cash flows provided by operating activities was $118.5 million. The Company intends to make the payments related to its debt and investments in capital expenditures with cash flows from operations. During the year ended December 31, 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 7 - 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 (i) the Term Loan Credit Agreement, (ii) the Revolving Credit Agreement, and (iii) its loan agreement previously entered into in March 2022 with Standard Charter Bank (the "SCB Credit Facility"), in each case 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 4 - 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 a purchase price of $107.8 million, and on June 28, 2024, sold certain non-operated upstream assets in Chelsea for a purchase price of $24.8 million. See *Note 3 - Acquisition and Dispositions* for further discussion on these transactions.

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.

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, 2024, 2023, and 2022. 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 and

• 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.

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 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 December 31, 2024. See *Note 4 - Debt*. The following table provides a reconciliation of cash, cash equivalents, and restricted cash to amounts shown in the consolidated balance sheets and 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

Inventory

Inventory primarily consists of materials and supplies and 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.

For tax years prior to the year ended December 31, 2024, the Company computed income tax expense on a separate tax return basis. During the year ended December 31, 2024, the Company deconsolidated from BNAC for federal income tax purposes and allocated tax attributes in accordance with the Code and related regulations. 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, 2024 and 2023. 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, 2024, 2023, and 2022, 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, 2024, 2023, and 2022.

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, 2024, 2023, and 2022, 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, 2024, 2023, and 2022.

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, 2024, 2023, and 2022.

Depreciation and amortization expense is included within depreciation, depletion, amortization, and accretion 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 to 5 years
Leasehold improvements	7 to 10 years

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 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 with terms longer than 12-months. 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, 2024 and 2023, all of the Company's leases are accounted for as operating leases. For the years ended December 31, 2024, 2023, and 2022, total lease expense for the Company was $1.2 million, $1.7 million, and $11.8 million, respectively. These expenses are included in depreciation, amortization, depletion, and accretion in the consolidated statements of operations. 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, NGL, 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.

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, 2024, 2023, and 2022, 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.

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.

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, 2024 and 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, and one 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, 2024, 2023, and 2022. 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, 2024, 2023, and 2022.

Equity-Based Compensation

The Company issues equity-based compensation in the form of restricted stock units ("RSUs"), which include time-based restricted stock units ("TRSUs") and performance-based restricted stock units ("PRSUs"). The TRSUs the Company authorizes to grant include service conditions, and the PRSUs the Company authorizes to grant include service conditions, market performance conditions, and non-market performance conditions. There is no obligation to make any future grants, and any such grants would require approval by the Company's board of directors. For accounting purposes, the grant date fair value of the TRSUs that were granted was determined based on the trading price of BKV's common stock price on the date of grant. 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.

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. Prior to the Company's IPO, equity-based compensation awards which ultimately settle in cash were accounted for as liabilities, and awards which were contingently settled in cash or shares of the Company's common stock were accounted for as mezzanine equity. Mezzanine equity classified awards were carried on the consolidated balance sheets at the greater of redemption value or initial carrying value. Prior to the IPO, changes in the redemption value of the awards resulted in a transfer from stockholders' equity to mezzanine equity on the consolidated balance sheets of the Company.

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 in the consolidated balance sheets using the cost method. Shares are held until authorized for redistribution by the Company's board of directors.

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 "Power JV Board"), and participation in the policy-making decisions of the 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 RSUs and the if-converted method for preferred stock. The Company includes potential shares of common stock for 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.

Recently Issued Accounting Standards

In December 2023, the Financial Standards Accounting Board ("FASB") issued Accounting Standard Update ("ASU") 2023-09 *Improvements to Income Tax Disclosures*, which requires public entities to disclose more consistent and detailed categories in their statutory to effective income tax rate reconciliations and further disaggregate income taxes paid by jurisdiction. For each annual period presented, the new standard requires disclosure of the year-to-date amount of income taxes paid (net of refunds received) disaggregated by federal, state, and foreign. It also requires additional disaggregated information on income taxes paid (net of refunds received) to an individual jurisdiction equal to or greater than 5% of total income taxes paid (net of refunds received). The standard is effective January 1, 2025. Management is currently evaluating the impact this standard will have on the Company's disclosures.

In November 2024, the FASB issued ASU 2024-03, *Disaggregation of Income Statement Expenses*. This standard requires that entities (i) disclose amounts of purchases of inventory, employee compensation, and depreciation, depletion, and amortization, including those recognized as part of oil and gas-producing activities (or other amounts of depletion expense) included in each relevant expense caption, (ii) include certain amounts that are already required to be disclosed under current GAAP in the same disclosure as the other disaggregation requirements, (iii) disclose a qualitative description of the amounts remaining in relevant expense captions that are not separately disaggregated quantitatively, and (iv) disclose the total amount of selling expenses and, in annual reporting periods, an entity's definition of selling expenses. This standard is effective January 1, 2027 with early adoption permitted. Management is currently evaluating the impact this standard will have on the Company's disclosures.

Recently Adopted Accounting Standards

In November 2023, the FASB issued ASU 2023-07, *Improvements to Reportable Segment Disclosures*, which requires entities to disclose the title of the chief operating decision maker and, on an interim and annual basis, significant segment expenses and the composition of other segment items for each segment's reported profit. The standard also permits disclosure of additional measures of segment profit. BKV adopted this guidance effective January 1, 2024 and currently identifies one operating and one reporting segment. See *Note 1 - Business and Basis of Presentation*, *Business Segment Information*.

Note 3 - Acquisition and Dispositions

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, the "Seller"), for $750.0 million (subject to working capital and other adjustments) and additional contingent payments totaling $50.0 million, if certain pricing thresholds were 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 in 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 were $225.1 million of total revenue and $130.6 million of income from operations.

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)

Supplemental Unaudited Pro Forma Information. The following pro forma financial information represents a summary of the historical consolidated results of operations for the year ended December 31, 2022, 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, including borrowings under the $570.0 million term loan and $75.0 million related party note, (iv) increase in accretion expense reflective of the fair market value of asset retirement obligations, (v) 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.

Supplemental Unaudited Pro Forma Information

(in thousands)	**Year Ended December 31, 2022**	
Total revenues and other operating income	$	1,253,623
Net income	$	476,567

Dispositions

On June 14, 2024, the Company sold its wholly-owned subsidiary, Chaffee, representing a non-operated interest in approximately 9,800 net acres and 116.0 gross (24.2 net) wells and 122 Bcfe of proved reserves in the Marcellus Shale in the Appalachian Basin of NEPA, as well as the Company's interest in the Repsol Oil and Gas operated midstream system, for $107.8 million. The Company recognized a gain on the sale of $7.1 million, net of transaction costs of approximately $3.5 million, which is included in the gain on sale of business in the consolidated statements of operations.

On June 28, 2024, Chelsea sold certain of its non-operated upstream assets, including interest in approximately 6,800 net acres and 214.0 gross (15.4 net) wells and 35 Bcfe of proved reserves in NEPA, for a purchase price of $24.8 million and transaction costs of approximately $0.5 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.

Following the divestiture of these assets, the Company held approximately 19,480 net acres in NEPA, 98% of which was held by production and, as of December 31, 2024, held approximately 19,100 net acres, 97% of which was held by production.

Note 4 - Debt

The following table summarizes the Company's debt balances:

	December 31,	
(in thousands)	**2024**	**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	165,000	—
Term Loan Credit Agreement	—	342,000
Long-term portion of unamortized debt issuance costs	—	(2,337)
Total long-term debt, net	165,000	339,663
Total debt, net	$ 165,000	$ 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 Agreement and cash on hand. During the year ended December 31, 2024, 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 early extinguishment of debt in the consolidated statements of operations.

RBL Credit Agreement

On June 11, 2024, the Company and BKV Upstream Midstream entered into the RBL Credit Agreement 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 December 31, 2024, the RBL Credit Agreement has a borrowing base of $750.0 million and an elected commitment of $600.0 million. As of March 31, 2025, $200.0 million of revolving borrowings and $14.1 million of letters of credit were outstanding under the RBL Credit Agreement, leaving $385.9 million of available capacity thereunder for future borrowings and letters of credit. The borrowing base was reduced by $50.0 million and the elected commitment was affirmed after the semiannual redetermination event, which was completed in November 2024. 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. During the year ended December 31, 2024, BKV Upstream Midstream paid $0.8 million of commitment fees, which is included in interest expense on the consolidated statements of operations.

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 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. As of December 31, 2024, BKV Upstream Midstream was in compliance with the terms and covenants of the RBL Credit Agreement.

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.

During the year ended December 31, 2024, 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 December 31, 2024, $6.9 million of unamortized debt issuance costs remained outstanding. As of December 31, 2024, the effective interest rate on the RBL Credit Agreement was 7.50% and the outstanding letters of credit was $14.1 million.

Subordinated Intercompany Loan Agreement

During the year ended December 31, 2024, the Company repaid the outstanding balance of $75.0 million, including interest, and subsequently terminated the related party loan with BNAC with proceeds from the revolving borrowings on the RBL Credit Agreement and the IPO.

Note 5 - Natural Gas Properties & Other Property and Equipment

As of December 31, 2024 and 2023, accumulated depreciation, depletion, and amortization for developed natural gas properties was $697.0 million and $560.0 million, respectively. For the years ended December 31, 2024, 2023, and 2022, depreciation, depletion, and amortization expense for developed natural gas properties was $188.7 million, $196.1 million, and $96.5 million, respectively.

Midstream assets consisted of the following:

	December 31,			
(in thousands)	2024		2023	
Compressor station	$	33,461	$	37,280
Meter station		67		721
Pipelines		243,116		280,854
Total		276,644		318,855
Accumulated depreciation		(17,285)		(19,399)
Midstream assets, net	$	259,359	$	299,456

As of December 31, 2024 and 2023, accumulated depreciation for midstream assets was $17.3 million and $19.4 million, respectively. For the years ended December 31, 2024, 2023, and 2022, depreciation expense on midstream assets was $6.9 million, $7.5 million, and $4.5 million, respectively.

Other property and equipment consisted of the following:

	December 31,			
(in thousands)	2024		2023	
Carbon capture, utilization, and sequestration	$	69,743	$	59,142
Buildings		15,707		15,707
Furniture, fixtures, equipment, and vehicles		19,306		15,101
Computer software		5,595		4,844
Leasehold improvements		1,685		1,685
Land		3,090		3,090
Construction in process		3,575		76
Total		118,701		99,645
Accumulated depreciation		(21,401)		(15,710)
Other property and equipment, net	$	97,300	$	83,935

For the years ended December 31, 2024, 2023, and 2022, depreciation expense for other property and equipment was $6.4 million, $5.7 million, and $4.4 million, respectively. During the year ended December 31, 2024, the Company received proceeds on the sale of other properties of $5.0 million, and recognized a gain on sale of these properties of $3.6 million, which is included in the gains on sales of assets in the consolidated statements of operations. During the year ended December 31, 2023, the Company received proceeds on the sale of other properties of $6.7 million, and recognized a gain on sale of these properties of $2.2 million, which is included in the gains on sales of assets in the consolidated statements of operations.

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, 2024 and 2023, the impact of the non-performance risk adjustment to the Company's fair value of commodity derivative liabilities was $6.6 million and $1.0 million, respectively.

Contingent consideration, minority ownership puttable shares, and equity-based compensation from the 2021 Plan (as defined in *Note 13 - Stockholders' Equity and Mezzanine Equity*) were measured at fair value using Level 3 valuation techniques. There were no transfers between fair value levels during the years ended December 31, 2024, 2023, and 2022.

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:

	December 31, 2024		
	Fair Value Measurements Using:		
(in thousands)	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
Financial liabilities			
Derivative instruments	$ 67,634	$ —	$ 67,634

	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 Devon Barnett Acquisition and the Exxon Barnett Acquisition. As of December 31, 2024, the contingent consideration is included in current liabilities in the consolidated balance sheets as a payable as the final payout was made of $20.0 million on January 8, 2025. The fair value of the contingent consideration as of December 31, 2023 represented management's best estimate if a third party was paid to assume the contingency and the fair value was determined using Monte Carlo simulations, which used 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 Devon Barnett Acquisition and the Exxon Barnett Acquisition contingencies are described further in *Note 16 - Commitments and Contingencies*. The Devon Barnett Acquisition was accounted for as an asset acquisition with the contingent consideration meeting the criteria of a derivative in accordance with ASC 815 - *Derivatives and Hedging*. See *Note 7 - Derivative Instruments* for further discussion.

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. Prior to the Company's IPO, its 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 unobservable (Level 3) inputs. Prior to the Company's IPO, 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, 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 13 - Stockholders' Equity and Mezzanine Equity*.

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%

(1) The Company uses the midpoint of valuation results when estimating the fair value of common stock.
(2) Represents an observable input.

The tables below sets forth the changes in the Company's Level 3 fair value measurements:

	Year Ended December 31, 2024			
(in thousands)	Contingent Consideration	Minority Ownership	Equity-Based Compensation	Total
Balance, beginning of period	$ 29,676	$ 59,988	$ 126,966	$ 216,630
Contingent consideration - settled	(20,000)	—	—	(20,000)
Mezzanine equity conversion	—	(42,995)	(74,993)	(117,988)
Grant date fair value of equity-based compensation, pre-IPO	—	(4)	(42,663)	(42,667)
Change in fair market value (all instruments)	(9,676)	(16,989)	(9,310)	(35,975)
Balance, end of period	$ —	$ —	$ —	$ —

	Year Ended December 31, 2023			
(in thousands)	Contingent Consideration	Minority Ownership	Equity-Based Compensation	Total
Balance, beginning of period	$ 88,051	$ 62,712	$ 89,171	$ 239,934
Contingent consideration - settled	(20,000)	—	—	(20,000)
Grant date fair value of equity-based compensation, pre-IPO	—	(2)	22,193	22,191
Change in fair market value (all instruments)	(38,375)	(2,722)	15,602	(25,495)
Balance, end of period	$ 29,676	$ 59,988	$ 126,966	$ 216,630

	Year Ended December 31, 2022			
(in thousands)	Contingent Consideration	Minority Ownership	Equity-Based Compensation	Total
Balance, beginning of period	$ 142,533	$ 49,841	$ 34,006	$ 226,380
Contingent consideration through acquisition	17,150	—	—	17,150
Contingent consideration - settled	(65,000)	—	—	(65,000)
Grant date fair value of equity-based compensation, pre-IPO	—	78	30,765	30,843
Change in fair market value (all instruments)	(6,632)	12,793	24,400	30,561
Balance, end of period	$ 88,051	$ 62,712	$ 89,171	$ 239,934

Note 7 - Derivative Instruments

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 Company also determined that the contingent consideration generated from the Devon Barnett Acquisition met the definition of a derivative in accordance with ASC 815 - *Derivative and Hedging*, and the fair value of the contingent consideration was $20.0 million and $47.5 million as of December 31, 2024 and 2023, respectively, and is included in contingent consideration payable and contingent consideration in the consolidated balance sheets. The change in the fair value of this contingent consideration was a gain of $7.5 million, $25.0 million, and $5.0 million for the years ended December 31, 2024, 2023, and 2022, respectively, and is included in gains on contingent consideration liabilities on the consolidated statements of operations. See *Note 16 - Commitments and Contingencies* for further discussion.

The derivative contracts outstanding as of December 31, 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 consolidated balance sheets:

		December 31, 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	$ 5,187	$ (5,187)	$ —
Noncurrent derivative assets	Commodity derivative assets	872	(872)	—
Current derivative liabilities	Other current liabilities	25,464	(5,187)	20,277
Noncurrent derivative liabilities	Other noncurrent liabilities	48,229	(872)	47,357

		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 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:

(in thousands)	Year Ended December 31, 2024	2023	2022
Gain (loss) on settled derivatives, net	$ 112,527	$ 90,179	$ (688,516)
Gain (loss) on unsettled derivatives, net	(146,679)	148,564	58,815
Derivative gains (losses), net	$ (34,152)	$ 238,743	$ (629,701)

Settled derivative gains, net for the year ended December 31, 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 year ended December 31, 2024. Settled derivative gains, 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 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 contracts prior to their contractual settlement dates. $1.3 million of such losses is attributable to early-terminated natural gas commodity derivative swap contracts covering production during the year ended December 31, 2022.

During the first quarter in 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.

On February 13, 2025 and February 14, 2025, the Company entered into agreements to buy put options and subsequently paid a net premium of $3.0 million and $13.2 million, respectively, for contracts that settle in 2026 and 2027. The call options have an established floor of $3.00 per MMBtu. If at the time of settlement the contracted settlement price falls below the floor, the counterparties pay the Company an amount equal to the difference between the contracted settlement price and the floor multiplied by the contract volumes.

Instrument	Index	Daily Volume (MMBtu)	Weighted Average Price Floor
2026			
Put options	NYMEX Henry Hub	100,000	$ 3.00
2027			
Put options	NYMEX Henry Hub	100,000	$ 3.00

Volume of Derivative Activities

As of December 31, 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 December 31, 2024 (in thousands)
2025					
Swap	104,225,000	$ 3.40			$ (12,460)
Collars	13,360,000		$ 3.71	$ 4.11	$ 4,017
2026					
Swap	57,825,000	$ 3.60			$ (18,419)
Collars	25,550,000		$ 3.67	$ 4.19	$ (78)
Call options	36,500,000			$ 5.00	$ (11,640)
2027					
Collars	29,200,000		$ 3.53	$ 3.93	$ (2,337)
Call options	36,500,000			$ 5.00	$ (12,365)

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, 2024 (in thousands)
2025				
Swap	Transco Leidy Basis	12,775,000	$ (0.86)	$ (1,750)
Swap	HSC Basis	29,200,000	$ (0.45)	$ (3,630)

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

Instrument	Commodity Reference Price	Gallons	Weighted Average Price (USD)	Fair Value as of December 31, 2024 (in thousands)
2025				
Swap	OPIS Purity Ethane Mont Belvieu	119,595,000	$ 0.24	$ (1,374)
Swap	OPIS IsoButane Mont Belvieu Non-TET	8,515,500	$ 0.89	$ (1,307)
Swap	OPIS Normal Butane Mont Belvieu Non-TET	10,998,750	$ 0.85	$ (1,623)
Swap	OPIS Propane Mont Belvieu Non-TET	46,882,500	$ 0.75	$ (1,409)
Swap	OPIS Natural Gasoline Mont Belvieu Non-TET	17,220,000	$ 1.42	$ (741)
2026				
Swap	OPIS Purity Ethane Mont Belvieu	94,762,500	$ 0.25	$ (2,028)
Swap	OPIS IsoButane Mont Belvieu Non-TET	2,388,750	$ 0.84	$ (120)
Swap	OPIS Normal Butane Mont Belvieu Non-TET	10,053,750	$ 0.82	$ (208)
Swap	OPIS Propane Mont Belvieu Non-TET	37,327,500	$ 0.70	$ (581)
Swap	OPIS Natural Gasoline Mont Belvieu Non-TET	16,275,000	$ 1.40	$ 419

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, 2024 and 2023, the liability has been accreted to its present value and, for the years ended December 31, 2024, 2023, and 2022, accretion expense of $14.1 million, $13.2 million, and $12.8 million, respectively, was recognized and included in depreciation, amortization, depletion, and accretion in the consolidated statements of operations.

The following table summarizes the activities of the Company's asset retirement obligations:

	Year Ended December 31,		
(in thousands)	**2024**	**2023**	**2022**
Balance, as of January 1,	$ 195,476	$ 182,300	$ 158,968
Additions through business combination	—	640	46,867
Liabilities incurred	42	89	303
Liabilities settled	(1,288)	(759)	(156)
Liabilities associated with property sold (1)	(7,133)	—	—
Revisions of estimates	—	—	(36,516)
Accretion of discount	14,061	13,206	12,834
Balance, as of December 31,	201,158	195,476	182,300
Less current portion	(2,363)	(2,271)	(1,165)
Asset retirement obligations, long-term	$ 198,795	$ 193,205	$ 181,135

(1) Liabilities associated with property sold relate to the sales of Chaffee and certain non-operated upstream assets in Chelsea. See *Note 3 - Acquisition and Dispositions* for further discussion.

Note 9 - Related Parties

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 year ended December 31, 2022, the Company recognized interest expense of $5.5 million.

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 year ended December 31, 2022, the Company recognized interest expense of $0.9 million.

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, 2024 and 2022, 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 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. Interest on the outstanding principal was SOFR plus an interest rate margin of 5.25%. During the year ended December 31, 2024, the Company repaid the outstanding balance of $75.0 million, including interest, and subsequently terminated the related party loan with BNAC with proceeds from the revolving borrowings on the RBL Credit Agreement and the IPO. As of December 31, 2023, interest payable under this loan was $11.4 million. For the years ended December 31, 2024, 2023, and 2022, interest expense recognized on this loan agreement was $5.2 million, $7.1 million, and $4.3 million, respectively.

As of December 31, 2024, the Company had accounts receivable of $14.7 million from BNAC for Section 45Q tax credits generated from the Barnett Zero Project, which is included in accounts receivable, related parties on the consolidated balance sheets. For the years ended December 31, 2024 and 2023, the Company recognized $14.0 million and $0.7 million, respectively, of income related to the Section 45Q tax credits, which is included in related party revenue on the consolidated statements of operations. Separately, as of December 31, 2024 and 2023, the Company had payables of $1.4 million and $0.9 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. In addition, as of December 31, 2024 and 2023, the Company had a receivable from BNAC of $0.2 million and $0.1 million, respectively, related to shared general and administrative expenses, which is included in accounts receivable, related parties on the consolidated balance sheets.

As of December 31, 2024 and 2023, the Company had accounts receivable from BKV-BPP Power, LLC of $0.5 million and $0.4 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, 2024, 2023, and 2022, the Company recognized $3.1 million, $3.6 million, and $2.7 million, respectively, of income related to the services provided under the ASA, which is included in related party revenue on the consolidated statements of operations.

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, 2024		
(in thousands)	**Pennsylvania**	**Texas**	**Total**
Natural gas	$ 38,795	$ 346,661	$ 385,456
NGLs	—	165,508	165,508
Oil	—	6,606	6,606
Total natural gas, NGL, and oil sales	$ 38,795	$ 518,775	$ 557,570
Marketing revenues	—	10,668	10,668
Midstream revenues	2,014	10,546	12,560
Related party and other	—	23,732	23,732
Total	$ 40,809	$ 563,721	$ 604,530

	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

(in thousands)	Year Ended December 31, 2022 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

As of December 31, 2024 and 2023, the Company's receivables from contracts with customers were $45.8 million and $32.8 million, respectively.

Note 11 - Accounts Payable and Accrued Liabilities

Accounts payable and accrued liabilities included in current liabilities consist of the following:

(in thousands)	December 31, 2024	2023
Accounts payable	$ 53,238	$ 47,504
Accrued payroll	23,435	18,189
Oil and gas production and other taxes payable	21,263	48,857
Revenues payable	17,921	21,765
Other accrued liabilities	5,509	12,858
Total	$ 121,366	$ 149,173

Note 12 - Equity-Based Compensation

2024 Equity and Incentive Compensation Plan

The Company's 2024 Equity and Incentive Compensation Plan (the “2024 Plan”) became effective immediately prior to the consummation of the IPO. The 2024 Plan permits the grant of awards to the non-employee directors, officers, and other employees of BKV Corp and its controlled subsidiaries in order to provide incentives and rewards for service and/or performance. The Company 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 the Company's common stock. Under the 2024 Plan, the Company can issue up to 5,000,000 shares of its common stock, which are subject to adjustment to reflect any extraordinary cash dividend, stock dividend, split, or combination of the Company's common stock. The aggregate number of shares of the Company's common stock available for award under the 2024 Plan will be reduced by one share of the Company's common stock for every one share of its common stock subject to an award granted under the 2024 Plan. Each grant of an award under the 2024 Plan will be evidenced by an award agreement that includes terms and provisions, determined by the Company's Compensation Committee (or other committee of the board of directors designated by the board to administer the 2024 Plan), which outlines the number of shares of common stock, earning or vesting terms, and any other terms consistent with the 2024 Plan.

Any shares of common stock awarded under the 2024 Plan that have been canceled, forfeited, expired, settled for cash shares, or is unearned (in whole or part) will be added back to the aggregate number of shares of common stock available under the 2024 Plan, with the exception of the following: (i) shares of common stock withheld by the Company in payment of the exercise price of a stock option; (ii) shares of common stock tendered or otherwise used in payment of the exercise price of a stock option; (iii) shares of common stock withheld by the Company or tendered or otherwise used to satisfy a tax withholding obligation; (iv) shares of 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 common stock reacquired by the Company on the open market or otherwise using cash proceeds from the exercise of stock options. As of December 31, 2024, 3,825,516 shares were available for future grants under the 2024 Plan.

Performance-Based Restricted Stock Units

During the year ended December 31, 2024, the Company granted 704,649 PRSUs under the 2024 Plan. These PRSUs cliff vest on December 31, 2026 and are subject to a performance period beginning January 1, 2024 and ending on December 31, 2026 (the "2024 PRSU Performance Period"). The table below summarizes the PRSU activity for the year ended December 31, 2024:

(in thousands, except per share amounts)	**Shares**	**Weighted Average Grant Date Fair Value**
Unvested PRSUs as of January 1, 2024	—	$ —
Granted	705	$ 12.23
Forfeitures	(2)	$ 12.23
Unvested PRSUs as of December 31, 2024	703	$ 12.23

These PRSUs are eligible to be earned based on three performance conditions: (i) annualized Total Shareholder Return ("aTSR") of the Company's common stock during the 2024 PRSU Performance Period, weighted at 30%, (ii) relative Total Shareholder Return ("rTSR") of the common stock of the Company's benchmark group during the 2024 PRSU Performance Period, weighted at 30%, and (iii) Return on Capital Employed ("ROCE") based on the average annual performance over the 2024 PRSU Performance Period, weighted at 40%.

The aTSR and rTSR components of the awards are market-based conditions valued using the Monte-Carlo Simulation pricing model, which calculates multiple potential outcomes and establishes grant date fair value based on the most likely outcome. For purposes of the grant date fair value during the year ended December 31, 2024, the aTSR and rTSR components assumed a risk free rate of 3.5%, a dividend yield of a immaterial amount, and volatility of 40% that used a combination of daily historical and implied volatility over a look back period commensurate with the remaining term of the assets. The weighted average grant date fair value of the aTSR and rTSR components of PRSU awards granted during the year ended December 31, 2024 was $6.78 and $9.91, respectively.

ROCE is considered to be a non-market performance condition. Thus, the likelihood of achievement must be reassessed at every reporting period, and compensation expense is adjusted accordingly. As of December 31, 2024, management estimates ROCE performance to be greater than the target performance level by approximately 27.5%. The grant date fair value of the PRSUs presented in the activity for the year ended December 31, 2024 takes into account the grant date fair value for ROCE, 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 component of PRSU awards granted during the year ended December 31, 2024 was $18.05.

As of December 31, 2024, there was $6.4 million of unrecognized compensation expense related to the 2024 PRSU awards, which will be amortized over a weighted average period of 2 years.

Equity-based compensation related to PRSUs was $0.8 million for the year ended December 31, 2024, which is included in general administrative expenses in the consolidated statements of operations.

Time-Based Restricted Stock Units

During the year ended December 31, 2024, the Company granted 469,835 TRSUs under the 2024 Plan. Under the applicable provisions of the 2024 Plan, the TRSU incentive award vests annually over three anniversary dates in equal portions with the first tranche vesting on January 1, 2025, subject to continued employment with the Company and board of director approval. The table below summarizes the TRSU activity for the year ended December 31, 2024:

(in thousands, except per share amounts)	**Shares**	**Weighted Average Grant Date Fair Value**
Unvested TRSUs as of January 1, 2024	—	$ —
Granted	470	$ 18.05
Forfeited	(1)	$ 18.05
Unvested TRSUs as of December 31, 2024	469	$ 18.05

As of December 31, 2024, there was $5.6 million of unrecognized compensation expense related to the 2024 TRSU awards, which will be amortized over a weighted average period of 2 years.

Equity-based compensation related to TRSUs was $2.8 million for the year ended December 31, 2024, which is included in general administrative expenses in the consolidated statements of operations.

Employee Stock Purchase Plan

The Company's Employee Stock Purchase Plan (the "ESPP") became effective immediately prior to the consummation of the IPO. A total of 500,000 shares of the Company's common stock is available for awards under the ESPP and only permits eligible employees to purchase shares of the Company's common stock through payroll deductions, which cannot exceed 10% of the employee's eligible compensation. 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 the Company's common stock. For the year ended December 31, 2024, the Company did not recognize any equity-based compensation expense related to the ESPP.

2021 Equity and Incentive Compensation Plan

On January 1, 2021, the BKV Corporation Long-Term Incentive Plan (the "2021 Plan") was established and as of December 31, 2024, 7,724,499 RSUs were considered to have been granted under ASC 718 - *Compensation-Stock Compensation* ("ASC 718"), 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 December 31, 2024, the awards considered granted under ASC 718 since inception equaled the number of RSUs legally granted. Prior to the Company's IPO, RSUs under the 2021 Plan were recognized in mezzanine equity on the consolidated balance sheets and were valued using unobservable inputs. See *Note 6 - Fair Value Measurements* for further detail.

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. As of December 31, 2023, the Company achieved its performance targets 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 January 1, 2024	3,967	$ 19.02
Vested [(1)]	(3,963)	$ 19.02
Forfeited [(2)]	(4)	$ 19.02
Unvested PRSUs as of December 31, 2024	—	$ —

(1) For the year ended December 31, 2024, the total weighted average fair value of the shares vested was $28.25.
(2) Forfeited award amounts took into consideration performance shares at the maximum performance level.

Due to the PRSU cliff vest, there was no equity-based compensation under the 2021 Plan for the year ended December 31, 2024. For the years ended December 31, 2023 and 2022, equity-based compensation related to the PRSUs was $22.2 million and $27.3 million, respectively. These costs are included in general and administrative expenses in the consolidated statements of operations.

Time-Based Restricted Stock Units

The following table summarizes the TRSU activity under the 2021 Plan for the year ended December 31, 2024:

(in thousands, except per share amounts)	Shares	Weighted-Average Grant Date Fair Value
Unvested TRSUs as of January 1, 2024	727	$ 22.37
Vested [(1)]	(659)	$ 22.12
Forfeited	(68)	$ 22.12
Unvested TRSUs as of December 31, 2024	—	$ —

(1) For the year ended December 31, 2024, the total weighted average fair value of the shares vested was $22.34.

For the years ended December 31, 2024, 2023, and 2022, equity-based compensation expense related to the TRSUs under the 2021 Plan was $12.7 million, $3.6 million, and $4.6 million, respectively. These costs are included in general and administrative expenses in the consolidated statements of operations. Upon consummation of the IPO, the remaining TRSUs from the 2021 Plan vested.

Equity Investments

The Company 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 a capital contribution in exchange for 7,500,000 shares of BKV common stock. To comply with a financial covenant under the Term Loan Credit Agreement, $138.3 million of BNAC's capital contribution was placed in a debt service reserve account, which was released upon termination of the Term Loan Credit Agreement. See *Note 2 - Summary of Significant Accounting Policies* for further information.

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 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 such equity awards, and per share amounts contained throughout these consolidated financial statements have been retroactively adjusted for all past and current periods presented.

Common Shares Issued and Outstanding

As of December 31, 2024 and 2023, the Company had 84,600,301 and 63,872,684, 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, 2024, 2023, and 2022.

There were no cash dividends declared or paid during the years ended December 31, 2024, 2023, and 2022.

Minority Ownership Puttable Shares — Mezzanine Equity

On May 1, 2020, the Company issued 47,350,000 shares, of which, 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, there were 1,976,689 of these minority shares outstanding. Upon consummation of the IPO, all Management Shares were converted into common stock. The Management Shares included a put and call feature which required 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 had the right to 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. Since the shares were not mandatorily redeemable, but could 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, management determined it was probable that the shares would become redeemable at the end of the three-year period and 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, 2024, 2023, and 2022, the Company recognized adjustments of $0.5 million, $2.5 million, and $11.9 million, respectively, to the carrying value of the Management Shares to adjust to redemption value.

No Management Shares were redeemed during the years ended December 31, 2024, 2023, and 2022.

Employee Stock Purchase Plan — Mezzanine Equity

The Company's Employee Stock Purchase Plan (the "2021 ESPP") was adopted on November 1, 2021 and reserved 3,735,294 shares of common stock for purchase by eligible employees of the Company. As of December 31, 2023, there were 146,116 of the 2021 ESPP shares outstanding. The number of shares available was subject to adjustment based on anti-dilution provisions in the Stockholders' Agreement. The 2021 ESPP allowed for certain eligible non-employees and members of the board of directors to purchase shares under the 2021 ESPP in addition to eligible employees of the Company. During the year ended December 31, 2022, the Company issued 2,563 shares of common stock under the 2021 ESPP. There were no shares issued under the 2021 ESPP during the years ended December 31, 2024 and 2023, and during the years ended December 31, 2024 and 2023, the Company redeemed 300 and 100 shares of common stock, respectively. The shares sold under the 2021 ESPP included a put right which allowed for holders of the 2021 ESPP shares to require the Company to purchase the shares upon the occurrence of certain events stipulated by the 2021 ESPP. The shares could also be purchased by the Company, at its discretion upon the occurrence of certain events, as stipulated in the 2021 ESPP. Because the shares were not mandatorily redeemable but could 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 2021 ESPP was recognized within mezzanine equity upon issuance. Management determined it was probable that the shares will become redeemable and 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 and 2022, the Company recognized an adjustment of $0.2 million and $0.9 million, respectively, to the carrying value of the 2021 ESPP shares and an immaterial amount during the year ended December 31, 2024. Upon consummation of the IPO, all 2021 ESPP shares were converted into common stock.

Equity-Based Compensation — Mezzanine Equity

As discussed in *Note 12 - Equity-Based Compensation*, the 2021 Plan included a put right available to the incentive award grant recipients. Accordingly, management determined it was probable the shares issued in settlement of the RSUs upon vesting will become redeemable and elected to carry the shares at redemption value which equals fair market value. During the years ended December 31, 2024, 2023, and 2022, the Company recognized an adjustment to the pro-rata portion of the RSUs which have vested in the amounts of $9.3 million, $15.6 million, and $24.4 million, respectively. The maturities related to the redemption feature were in accordance with the vesting terms discussed in *Note 12 - Equity-Based Compensation*, and took into account the three year and 181 day holding periods. During the years ended December 31, 2024, 2023, and 2022, the Company issued 2,696,587, 133,622, and 109,338 of common stock, respectively, upon vesting of RSUs, net of shares withheld for income taxes. As of December 31, 2023, the Company had 301,134 shares of common stock issued in settlement of vested incentive awards outstanding, which is included in equity-based compensation within mezzanine equity on the consolidated balance sheets of the Company at redemption value of $7.9 million. Upon consummation of the IPO, shares related to equity-based compensation in mezzanine equity were converted into common stock.

Treasury Stock

During the year ended December 31, 2024, the Company purchased 150 shares for an immaterial amount at a weighted average price of $26.34 per share. During the year ended December 31, 2023, the Company purchased, 20,748 shares for $0.6 million at a weighted average price of $29.09 per share, and during the year ended December 31, 2022, the Company purchased 110 shares for an immaterial amount at a weighted average price of $33.58 per share.

Note 14 - Equity Method Investment

The Company is a 50% owner of BKV-BPP Power, which is accounted for as an equity method investment. On July 10, 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 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.

BKV-BPP Power has a term loan from each of its affiliates, BNAC and BPPUS, each in the amount of $141.0 million, both of which mature on November 1, 2026.

In December 2021, the Company entered into the ASA with BKV-BPP Power, in which the Company provides certain services as required by the ASA, on an annual basis with options to extend. During the years ended December 31, 2024, 2023, and 2022, the Company recognized revenues of $3.1 million, $3.6 million, and $2.7 million, respectively, related to the services provided under the ASA, which is included in related party and other on the consolidated statements of operations.

During the years ended December 31, 2024, 2023, and 2022, the Company recognized, based on its 50% ownership interest in BKV-BPP Power, earnings of $10.4 million, $16.9 million, and $8.5 million, respectively. For the year ended December 31, 2024, BKV-BPP Power's total revenues, net, included unrealized derivative gains of $65.7 million and operating expenses included unrealized derivative losses of $1.7 million. For the year ended December 31, 2023, BKV-BPP Power's total revenues, net, included unrealized derivative losses of $74.2 million and operating expenses included unrealized derivative gains of $0.6 million. For the year ended December 31, 2022, BKV-BPP Power's total revenues, net, included unrealized derivative gains of $4.3 million.

On September 27, 2023, the Power JV Board authorized a dividend to the Company of $10.0 million, and on October 17, 2023, the dividend was paid.

The table below sets forth a reconciliation of BKV Corp's investment in BKV-BPP Power:

Reconciliation of Equity Method Investment (in thousands)	
Balance as of December 31, 2021	$ 89,320
Equity in earnings of BKV-BPP Power	8,493
Direct transaction costs	72
Balance as of December 31, 2022	97,885
Equity in earnings of BKV-BPP Power	16,865
Dividends from Power Joint Venture	(10,000)
Balance as of December 31, 2023	104,750
Equity in earnings of BKV-BPP Power	10,423
Balance as of December 31, 2024	$ 115,173

The table below sets forth the summarized financial information of BKV-BPP Power:

Balance Sheet (in thousands)	December 31, 2024[1]	December 31, 2023[1]
Current assets	$ 140,865	$ 142,672
Noncurrent assets	842,491	880,097
Total assets	$ 983,356	$ 1,022,769
Current liabilities	$ 70,994	$ 122,334
Noncurrent liabilities	685,045	694,203
Total liabilities	756,039	816,537
Members' equity	227,317	206,232
Total liabilities and members' equity	$ 983,356	$ 1,022,769

(1) Amounts are based on BKV-BPP Power's audited financial statements.

Income Statement (in thousands)	Year Ended December 31, 2024[1]	2023[1]	2022[2]
Total revenues, net	$ 459,880	$ 326,604	$ 294,736
Depreciation and amortization	37,967	31,752	21,547
Operating expenses	331,396	211,323	233,683
Income from operations	90,517	83,529	39,506
Interest expense	(72,908)	(50,524)	(19,662)
Other income	3,476	863	377
Net income	$ 21,085	$ 33,868	$ 20,221

(1) Amounts are based on BKV-BPP Power's audited financial statements.
(2) Amounts are based on BKV-BPP Power'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 included a cross default provision pursuant to which a default by the Company related to the covenants under the Company's Term Loan Credit Agreement would have caused 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 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 bills working interest owners for costs related to development of the Company's natural gas properties. As of December 31, 2024 and 2023, the Company's receivables from contracts with customers were $45.8 million and $32.8 million, respectively. Also, as of December 31, 2024 and 2023, one purchaser accounted for more than 10% of accounts receivables, and for the years ended December 31, 2024, 2023, and 2022, the same purchaser's revenues were $380.6 million, $476.5 million, and $1.1 billion, respectively. Another purchaser's revenues, that also accounted for more than 10% of the Company's revenues for the years ended December 31, 2024, 2023, and 2022, amounted to $146.0 million, $170.6 million, and $282.3 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. As of December 31, 2024, all known liabilities were 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, results may change in future periods. 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 recorded a contingent liability of approximately $5.3 million that was carried over from the NEPA acquisition for remitting lease related payments to certain leaseholders. During the year ended December 31, 2024, a judgment was issued in court ruling that BKV was not responsible for this liability and the likelihood of the case being taken up to the supreme court would be minimal. As such, the liability was removed and is reflected in other income on the consolidated statements of operations. In 2021, the Company also recorded an additional $0.4 million of contingent liabilities that was remediated during the year ended December 31, 2024 and is reflected as a reduction in general and administrative expenses on the consolidated statements of operations.

As a part of the consideration paid for the Devon Barnett Acquisition, additional cash consideration would be required to be paid by the Company if certain thresholds were 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 were 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. Payments were due in the month following the end of the respective measurement period for which the hurdle rates were set. On January 13, 2023, the Company paid the 2022 portion of the arrangement of $65.0 million. On January 12, 2024, the Company paid the 2023 contingent consideration of $20.0 million. As of December 31, 2024, the final 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 8, 2025. As described in *Note 6 - Fair Value Measurements* and *Note 7 - Derivative Instruments*, the contingent consideration was accounted for as a derivative instrument. 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, the Company's estimate of the fair value of the unsettled contingent consideration was $47.5 million. For the years ended December 31, 2024, 2023, and 2022, the change in the fair value of the contingent consideration were gains of $7.5 million, $25.0 million, and $5.0 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 was recognized in the gains on contingent consideration liabilities on the consolidated statements of operations.

In conjunction with the Exxon Barnett Acquisition (see *Note 3 - Acquisition and Dispositions*), additional cash consideration was required to be paid by the Company if certain thresholds for future Henry Hub natural gas prices were met for the years ended December 31, 2024 and 2023. Based on the thresholds for these periods, no payouts were required. As of December 31, 2024 and 2023, the fair value of the contingent consideration was zero and $2.2 million, respectively. For the years ended December 31, 2024, 2023, and 2022, the change in the fair value of the contingent consideration were gains of $2.2 million, $13.4 million, and $1.6 million, respectively. These changes in the fair value during these periods reduced the associated liability on the consolidated balance sheets and recognition of the gain was recognized in the gains on contingent consideration liabilities on the consolidated statements of operations. Refer to *Note 6 - Fair Value Measurements* for the valuation methodology and associated inputs.

The Company has volume commitments in the form of gathering, processing, and transportation agreements with various third parties that require delivery of 1,139,363,556 dekatherms of natural gas. The significant majority of the agreements terminate by 2029, with one agreement extending through 2036. As of December 31, 2024, the aggregate undiscounted future payments required under these contracts total $320.6 million.

A summary of the Company's commitments, excluding contingent consideration, as of December 31, 2024, is provided in the following table:

(in thousands)	**2025**	**2026**	**2027**	**2028**	**2029**	**Thereafter**	**Total**
RBL Credit Agreement	$ —	$ —	$ —	$ 165,000	$ —	$ —	$ 165,000
Interest payable	550	—	—	—	—	—	550
Operating lease payments	1,253	1,047	908	924	947	3,662	8,741
Volume commitments	68,612	66,739	58,959	53,144	34,257	38,929	320,640
Total	$ 70,415	$ 67,786	$ 59,867	$ 219,068	$ 35,204	$ 42,591	$ 494,931

Note 17 - Income Taxes

The Company's income (loss) before income taxes has been incurred in the United States. The Company's income tax (expense) benefit consisted of the following:

Tax (Expense) Benefit

	Year Ended December 31,		
(in thousands)	**2024**	**2023**	**2022**
Current tax (expense) benefit			
United States federal income tax	$ (573)	$ —	$ 30,165
Various state income taxes	(633)	4,169	(3,752)
Total current income tax (expense) benefit	(1,206)	4,169	26,413
Deferred tax (expense) benefit			
United States federal income tax	44,463	(29,569)	(86,772)
Various state taxes	348	(2,825)	(2,293)
Total deferred income tax (expense) benefit	44,811	(32,394)	(89,065)
Income tax (expense) benefit	$ 43,605	$ (28,225)	$ (62,652)

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

	Year Ended December 31,		
(in thousands)	**2024**	**2023**	**2022**
Income (loss) before income taxes	$ (186,475)	$ 145,143	$ 472,794
Federal statutory rate	21.0 %	21.0 %	21.0 %
Income tax (provision) benefit based on statutory rate	39,160	(30,480)	(99,287)
(Increase) decrease in income taxes resulting from:			
State tax (expense) benefit, net of federal benefit	4,476	(4,002)	(9,948)
Change in state tax rate, net of federal effect	(4,400)	1,177	3,005
Deferred tax activity	(1,332)	488	(56)
Bargain purchase gain	—	—	38,139
Excess tax benefits from vesting of restricted shares	3,829	373	64
Section 162(m) limitation	(8,881)	—	—
Payable true up	(778)	4,067	(983)
Marginal well credit	7,644	94	6,417
Investment tax credit	1,010	—	—
Nontaxable 45Q revenue	2,944	147	—
Other	(67)	(89)	(3)
Income tax (expense) benefit	$ 43,605	$ (28,225)	$ (62,652)

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:

Recognized Deferred Income Tax Assets and Liabilities

(in thousands)	December 31, 2024	2023
Deferred tax assets		
Fair value of derivative financial instruments	$ 9,018	$ —
Asset retirement obligations	46,240	43,578
Equity-based compensation	494	17,220
Contingent consideration	4,597	12,338
Interest expense carryforward	33,029	22,721
Net operating loss carryforward	35,826	29,591
Accrued bonuses	4,218	3,424
Marginal well credit	13,180	4,497
Other	7,373	3,789
Total deferred tax asset	153,975	137,158
Deferred tax liabilities		
Property and equipment	(193,977)	(216,969)
Investment in joint venture	(46,226)	(37,283)
Fair value of derivative financial instruments	—	(24,307)
Other	(2,460)	(2,567)
Total deferred tax liability	(242,663)	(281,126)
Deferred tax liability, net	$ (88,688)	$ (143,968)

As of December 31, 2024, the Company has a net operating loss ("NOL") carryforward deferred tax asset for federal tax purposes of approximately $35.7 million, which does not expire and a NOL carryforward deferred tax asset for state tax purposes of $0.1 million, which expires in 2043. In addition, as of December 31, 2024, the Company has a Section 163(j) interest expense carryforward deferred tax asset of $33.0 million, which does not expire, marginal well credits of $13.2 million that expire between 2041 and 2044, and investment tax credits of $1.1 million that expire between 2045 and 2046. Section 382 of the Code limits the use of NOL carryforwards, 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, 2024, the Company does not believe that its net operating losses and Section 163(j) interest expense carryforwards are currently subject to the limits of Section 382.

Due to the proportional change in BNAC's beneficial ownership of the Company resulting from the IPO, the Company deconsolidated from BNAC for federal income tax purposes. Based on the Code and related regulations, the Company allocated the cumulative NOL carryforwards, Section 163(j) interest expense carryforwards, and other general business tax credits. This impacted the Company's deferred tax liability, net balance by increasing the NOL carryforward and other general business tax credits of $14.3 million and $2.5 million, respectively, and reducing Section 163(j) interest expense carryforward of $6.3 million for the year ended December 31, 2024, as reflected in the table above, with the offset to additional paid-in capital.

As described in *Note 1 - Business and Basis of Presentation*, management revised the Company's previously issued consolidated financial statements to correct a $7.4 million understatement of deferred tax liabilities, net as of December 31, 2024. Presented below are the revisions to the previously issued financial statements.

(in thousands)	December 31, 2023 As Previously Reported	Adjusted	As Revised
Deferred tax assets			
Net operating loss carryforward	$ 27,583	$ 2,008	$ 29,591
Interest expense carryforward	21,769	952	22,721
Other	2,466	1,323	3,789
Total deferred tax asset	132,875	4,283	137,158
Deferred tax liabilities			
Property and equipment	(206,576)	(10,393)	(216,969)
Other	(1,233)	(1,334)	(2,567)
Total deferred tax liability	(269,399)	(11,727)	(281,126)
Deferred tax liability, net	$ (136,524)	$ (7,444)	$ (143,968)

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 and liabilities, projected future taxable income, and tax planning strategies in making this assessment. Accordingly, as of December 31, 2024 and 2023, 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 had no unrecognized tax benefits during the years ended December 31, 2024, 2023, and 2022 and had no unrecognized tax benefit balances as of December 31, 2024 and 2023. The Company is generally subject to potential federal and state examination for the tax years on and after December 31, 2021. For Texas, the Company is subject to examination for the tax years on and after December 31, 2020.

Note 18 - 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:

	Year Ended December 31,		
(in thousands, except per share amounts)	**2024**	**2023**	**2022**
Basic weighted average common shares outstanding	71,288	60,730	58,659
Add: dilutive effect of TRSUs	—	172	351
Add: dilutive effect of PRSUs	—	3,478	2,980
Diluted weighted average of common shares outstanding	71,288	64,380	61,990
Weighted average number of outstanding securities excluded from the calculated of diluted loss per share:			
TRSUs	264	—	—
PRSUs	2,523	—	—

Note 19 - 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:

	December 31,	
(in thousands)	**2024**	**2023**
Developed properties	$ 2,315,167	$ 2,370,156
Undeveloped properties	10,757	15,846
Total capitalized costs	2,325,924	2,386,002
Less: accumulated depreciation, depletion, and amortization	(697,002)	(560,016)
Net capitalized costs	$ 1,628,922	$ 1,825,986

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)	**2024**	**2023**	**2022**
Undeveloped property acquisition costs	$ 775	$ 335	$ 290
Acquisitions (1)	—	9,885	431,897
Development costs	95,427	107,544	253,179
Total cost incurred	96,202	117,764	685,366
Asset retirement obligations (2)	42	89	38,337
Total costs incurred including asset retirement obligations	$ 96,244	$ 117,853	$ 723,703

(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, 2024, 2023, and 2022 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, 2022	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
Net purchases 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
Revision of previous estimates	(485,190)	(35,891)	(2,401)	(714,942)
Extensions and discoveries	79,148	9,197	813	139,208
Improved recoveries	38,224	10	2,324	52,228
Net sales of minerals in place	(149,963)	—	—	(149,963)
Production	(228,683)	(9,859)	(96)	(288,413)
December 31, 2024	2,236,031	147,622	1,691	3,131,909
Proved developed reserves as of:				
January 1, 2023	3,798,027	170,840	1,111	4,829,733
December 31, 2023	2,443,072	156,399	992	3,387,418
December 31, 2024	2,059,983	134,016	878	2,869,347
Proved undeveloped reserves as of:				
January 1, 2023	1,057,649	40,660	758	1,306,157
December 31, 2023	539,423	27,766	59	706,373
December 31, 2024	176,048	13,606	813	262,562

(in MMcfe)	Developed	Undeveloped	Total
January 1, 2022	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
Revision of previous estimates	(235,580)	(479,362)	(714,942)
Extensions and discoveries	—	139,208	139,208
Improved recoveries	52,228	—	52,228
Sale of minerals in place	(103,887)	(46,076)	(149,963)
Production	(288,413)	—	(288,413)
Undeveloped reserves converted to developed	57,581	(57,581)	—
December 31, 2024	2,869,347	262,562	3,131,909

2024 Activity

During the year ended December 31, 2024, the Company's proved reserves decreased by 961.9 Bcfe. The decrease in proved reserves was primarily attributable to decreased commodity pricing and changes in the Company's planned drilling activity, which resulted in total downward revisions of 714.9 Bcfe. In addition, in June 2024, the Company sold its wholly-owned subsidiary, Chaffee and certain of its non-operated upstream assets in Chelsea decreasing reserves by 150.0 Bcfe. As discussed below, these decreases were partially offset by extensions and discoveries and improved recoveries experienced by the Company in 2024, which resulted in net increases to proved reserves of 139.2 Bcfe and 52.2 Bcfe, respectively. The Company produced 288.4 Bcfe during the year ended December 31, 2024.

Revisions of previous estimates — Primarily consisted of downward revisions to proved developed reserves and proved undeveloped reserves of 235.6 Bcfe and 213.7 Bcfe, respectively, as a result of lower average pricing during 2024 for natural gas, NGLs, and oil. Additional downward revisions were made to proved undeveloped reserves of 265.6 Bcfe due to the Company's lower capital spend and the resulting reduction in drilling activity during 2024. Changes to the Company's drilling schedule moved the development of 38.0 gross (35.1 net) locations in NEPA and the Barnett beyond the SEC requirement of developing PUD reserves five years from initial booking. These 38.0 gross (35.1 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 — Added 139.2 Bcfe of proved undeveloped reserves across 98.0 gross (89.4 net) locations driven by our optimized capital allocation and enhanced drilling program, which reduced costs and extended lateral lengths during the year ended December 31, 2024.

Improved recoveries — Added 52.2 Bcfe of proved developed reserves achieved through the continued enhancement of recovery techniques applied to producing wells during the year ended December 31, 2024.

Sale of minerals in place — Consisted of 103.9 Bcfe and 46.1 Bcfe of divested proved developed reserves and proved undeveloped reserves, respectively, of Chaffee assets and certain non-operated upstream assets in Chelsea, both sold in June 2024, which represented 330.0 gross (39.6 net) locations in NEPA.

Conversions of proved undeveloped reserves to proved developed reserves — Consisted of 57.6 Bcfe related to the completion of 8.0 gross (7.9 net) wells during the year ended December 31, 2024 that were converted to proved developed wells, previously classified as proved undeveloped. Development costs relating to the development of the Company's proved undeveloped reserves were $135.1 million for the year ended December 31, 2024.

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 (104.8 net) locations in NEPA and the Barnett beyond the SEC requirement of developing PUD reserves five years from initial booking. These 112.0 gross (104.8 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 below in *Extensions and discoveries*. 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 the Devon Barnett Acquisition. These locations are more rich in NGLs than the previously recognized locations removed from the 2021 drilling schedule as discussed above in *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.

Purchase 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.

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	**Year Ended December 31,**		
(in thousands)	**2024**	**2023**	**2022**
Future cash inflows	$ 6,207,197	$ 9,691,057	$ 34,992,383
Future production costs	(4,026,521)	(5,799,209)	(11,967,176)
Future development costs [(1)]	(666,194)	(977,333)	(1,859,661)
Future income tax expense	(96,180)	(406,937)	(4,572,275)
Future net cash flows	1,418,302	2,507,578	16,593,271
10% annual discount for estimated timing of cash flows	(785,216)	(1,445,245)	(9,599,669)
Standardized measure of discounted future net cash flows related to proved reserves	$ 633,086	$ 1,062,333	$ 6,993,602

(1) Includes abandonment costs.

The following table summarizes the changes in the Standardized Measure:

	Year Ended December 31,		
(in thousands)	**2024**	**2023**	**2022**
Balance, beginning of period	$ 1,062,333	$ 6,993,602	$ 2,412,889
Net change in sales and transfer prices and in production (lifting) costs related to future production	(272,270)	(5,386,961)	4,656,150
Changes in estimated future development costs	(2,933)	91,657	43,101
Sales and transfers of natural gas, NGLs, and oil produced during the period	(271,692)	(201,884)	(1,293,492)
Net change due to extensions, discoveries, and improved recoveries	18,261	36,107	824,295
Net change due to purchases (sales) of minerals in place	(90,531)	—	1,649,737
Net change due to revisions in quantity estimates	(74,031)	(3,058,900)	(86,088)
Previously estimated development costs incurred during the period	24,291	27,598	37,784
Net change in future income taxes	131,401	1,790,684	(1,299,320)
Accretion of discount	123,255	861,914	322,498
Changes in timing and other	(14,998)	(91,484)	(273,952)
Total discounted cash flow as end of period	$ 633,086	$ 1,062,333	$ 6,993,602

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As required by Rules 13a-15(b) and 15d-15(b) under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), we have evaluated, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) as of the end of the period covered by this Annual Report on Form 10-K. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the Commission's rules and forms, and that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer concluded that due to the presence of our material weakness described below, as of December 31, 2024, our disclosure controls and procedures were not effective.

Material Weakness in Internal Control over Financial Reporting

As of December 31, 2024, a material weakness 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 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 (i) audit adjustments to income tax benefit, income taxes payable to related party, and deferred tax assets and liabilities in the consolidated financial statements as of December 31, 2021 and for the year then ended, (ii) an immaterial audit adjustment to the supplemental cash flow 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 as of and for the year ended December 31, 2023, (iii) audit adjustments to deferred tax liabilities and additional paid-in capital as of December 31, 2024, and (iv), the revision of our previously issued financial statements for the interim and annual periods included in the years ended December 31, 2021, 2022, and 2023, and interim periods included in the year ended December 31, 2024. This material weakness 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 this material weakness, we believe our consolidated financial statements fairly present, in all material respects, our financial condition, results of operations, and cash flows for the periods presented, in accordance with GAAP.

Remediation Efforts to Address the Material Weakness

We have taken steps towards remediating this material weakness primarily by designing and implementing additional internal controls, including those related to 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 this material weakness, the measures we have taken, and plan to take, may not be effective.

Inherent Limitations on Effectiveness of Controls and Procedures

In designing and evaluating the disclosure controls and procedures and internal control over financial reporting, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives. In addition, the design of disclosure controls and procedures and internal control over financial reporting must reflect the fact that there are resource constraints and that management is required to apply judgment in evaluating the benefits of possible controls and procedures relative to their costs.

Changes in Internal Control over Financial Reporting

There were no changes in the Company's internal control over financial reporting during the quarter ended December 31, 2024 that have materially affected, or are reasonably likely to materially affect our internal controls over financial reporting.

Management's Report on Internal Control Over Financial Reporting

This Annual Report on Form 10-K does not include a report of management's assessment regarding the effectiveness of the Company's internal control over financial reporting or an attestation report of the Company's registered public accounting firm regarding internal control over financial reporting due to a transition period established by rules of the SEC for newly public companies.

ITEM 9B. OTHER INFORMATION

Securities Trading Plans of Directors and Executive Officers

On November 22, 2024, Ms. Lindsay Larrick, Chief Legal and Chief Administrative Officer and an officer of the Company as defined in Rule 16a-1(f) of the Securities Exchange Act of 1934, adopted a trading arrangement for the sale of securities of the Company’s common stock (a “Rule 10b5-1 Trading Plan”), as defined in Regulation S-K, Item 408. Ms. Larrick's Rule 10b5-1 Trading Plan, which has a plan end date of March 31, 2026, provides for the sale of up to 123,374 shares of common stock pursuant to the terms of the plan.

On November 27, 2024, Mr. Matt Johnson, Managing Director of BKV dCarbon Ventures and an officer of the Company as defined in Rule 16a-1(f) of the Securities Exchange Act of 1934, adopted a Rule 10b5-1 Trading Plan, as defined in Regulation S-K, Item 408. Mr. Johnson’s Rule 10b5-1 Trading Plan, which has a plan end date of July 31, 2025, provides for the sale of up to 76,657 shares of common stock pursuant to the terms of the plan.

On December 9, 2024, Mr. Eric Jacobsen, President — Upstream and an officer of the Company as defined in Rule 16a-1(f) of the Securities Exchange Act of 1934, adopted a Rule 10b5-1 Trading Plan, as defined in Regulation S-K, Item 408. Mr. Jacobsen’s Rule 10b5-1 Trading Plan, which has a plan end date of August 31, 2025, provides for the sale of up to 94,050 shares of common stock pursuant to the terms of the plan.

On December 12, 2024, Mr. Ethan Ngo, Chief Corporate Development Officer and an officer of the Company as defined in Rule 16a-1(f) of the Securities Exchange Act of 1934, adopted a Rule 10b5-1 Trading Plan, as defined in Regulation S-K, Item 408. Mr. Ngo’s Rule 10b5-1 Trading Plan, which has a plan end date of November 11, 2025, provides for the sale of up to 195,003 shares of common stock pursuant to the terms of the plan.

On December 12, 2024, Mr. Javier Hinojosa, Vice President of Retail Power and an officer of the Company as defined in Rule 16a-1(f) of the Securities Exchange Act of 1934, adopted a Rule 10b5-1 Trading Plan, as defined in Regulation S-K, Item 408. Mr. Hinojosa’s Rule 10b5-1 Trading Plan, which has a plan end date of November 28, 2025, provides for the sale of up to 70,981 shares of common stock pursuant to the terms of the plan.

On December 12, 2024, Mr. David Tameron, Vice President, Strategic Finance and IR and an officer of the Company as defined in Rule 16a-1(f) of the Securities Exchange Act of 1934, adopted a Rule 10b5-1 Trading Plan, as defined in Regulation S-K, Item 408. Mr. Tameron’s Rule 10b5-1 Trading Plan, which has a plan end date of July 1, 2025, provides for the sale of up to 9,509 shares of common stock pursuant to the terms of the plan.

On December 13, 2024, Mr. Bradley Birkelo, Senior Vice President, Subsurface and an officer of the Company as defined in Rule 16a-1(f) of the Securities Exchange Act of 1934, adopted a Rule 10b5-1 Trading Plan, as defined in Regulation S-K, Item 408. Mr. Birkelo’s Rule 10b5-1 Trading Plan, which has a plan end date of February 27, 2026, provides for the sale of up to 23,523 shares of common stock pursuant to the terms of the plan.

On December 13, 2024, Mr. John Jimenez, Chief Financial Officer and an officer of the Company as defined in Rule 16a-1(f) of the Securities Exchange Act of 1934, adopted a Rule 10b5-1 Trading Plan, as defined in Regulation S-K, Item 408. Mr. Jimenez’s Rule 10b5-1 Trading Plan, which has a plan end date of December 11, 2026, provides for the sale of up to 58,204 shares of common stock pursuant to the terms of the plan.

On December 13, 2024, Ms. Lauren Read, Vice President Operations of BKV dCarbon Ventures and an officer of the Company as defined in Rule 16a-1(f) of the Securities Exchange Act of 1934, adopted a Rule 10b5-1 Trading Plan, as defined in Regulation S-K, Item 408. Ms. Read’s Rule 10b5-1 Trading Plan, which has a plan end date of May 30, 2025, provides for the sale of up to 61,605 shares of common stock pursuant to the terms of the plan.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTION THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The names of our executive officers and their ages, titles and biographies as of the date hereof are incorporated by reference from Item 1 of Part I of this report. The other information called for by this Item 10 is incorporated herein by reference to the definitive proxy statement to be filed by BKV pursuant to Regulation 14A of the General Rules and Regulations under the Securities Exchange Act of 1934 not later than 120 days after the close of our fiscal year ended December 31, 2024 (the "2025 Proxy Statement").

BKV has adopted an insider trading policy and procedures governing the purchase, sale and other disposition of BKV's securities by directors, officers and employees that is reasonably designed to promote compliance with insider trading laws, rules and regulations and applicable NYSE listing standards. A copy of BKV's insider trading policy is filed as an exhibit to this Annual Report on Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

The information called for by this Item 11 is incorporated herein by reference to the 2025 Proxy Statement.

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

The information called for by this Item 12 is incorporated herein by reference to the 2025 Proxy Statement.

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

The information called for by this Item 13 is incorporated herein by reference to the 2025 Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information called for by this Item 14 is incorporated herein by reference to the 2025 Proxy Statement.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following financial statements, financial statement schedules and exhibits are filed as part of this report:

1. *Financial Statements*. BKV's consolidated financial statements are included in Item 8 of Part II of this report. Reference is made to the accompanying Index to Financial Statements.

2. *Financial Statement Schedules*. No financial statement schedules are applicable or required.

3. *Exhibits*. The exhibits listed below in the Index of Exhibits are filed, furnished or incorporated by reference pursuant to the requirements of Item 601 of Regulation S-K.

		Incorporated by Reference				
Exhibit Number	Description	Form	SEC File Number	Exhibit	Filing Date	Filed or Furnished Herewith
2.1+‡	Purchase and Sale Agreement, dated December 17, 2019, between Devon Energy Production Company, L.P. and BKV Barnett, LLC.	S-1	333-268469	2.1	8/12/22	
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.	S-1	333-268469	2.2	8/12/22	
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.	S-1	333-268469	2.3	8/12/22	
3.1	Second Amended and Restated Certificate of Incorporation of BKV Corporation.	8-K	001-42282	3.1	9/27/24	
3.2	Second Amended and Restated Bylaws of BKV Corporation.	8-K	001-42282	3.2	9/27/24	
4.1	Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934.					X
10.1†	Employment Agreement, dated August 4, 2020, between BKV Corporation and Christopher P. Kalnin.	S-1	333-268469	10.16	8/12/22	
10.2†	Employment Agreement, dated January 11, 2021, between BKV Corporation and John T. Jimenez.	S-1	333-268469	10.17	8/12/22	
10.3†	Employment Agreement, dated February 18, 2020, between Kalnin Ventures LLC and Eric Jacobsen.	S-1	333-268469	10.18	8/12/22	
10.4†	Employment Agreement, dated October 15, 2018, between Kalnin Ventures LLC and Lindsay B. Larrick.	S-1	333-268469	10.20	8/12/22	
10.5†	Employment Agreement, dated April 1, 2018, between Kalnin Ventures LLC and An Sao (Ethan) Ngo.	S-1	333-268469	10.21	8/12/22	
10.6†	Limited Liability Company Agreement of BKV-BPP Power, LLC, dated October 29, 2021.	S-1	333-268469	10.22	8/12/22	
10.7†	BKV Corporation Non-Employee Director Compensation Program.	S-1	333-268469	10.24	9/16/22	
10.8†	Letter Agreement, dated November 14, 2022, between Kalnin Ventures, LLC and Barry Turcotte.	S-1	333-268469	10.31	12/22/22	
10.9†	Employment Agreement, effective October 9, 2023, between BKV Corporation and Mary Rita Valois.	S-1	333-268469	10.42	1/12/24	
10.10	Credit Agreement dated as of June 11, 2024 among BKV Corporation, BKV Upstream Midstream, LLC, Citibank, N.A., and the Lenders party thereto.	S-1	333-268469	10.44	7/5/24	
10.11	Stockholders' Agreement, dated September 27, 2024, by and between BKV Corporation and Banpu North America Corporation.	8-K	001-42282	10.1	9/27/24	

10.12	Amended and Restated Tax Sharing Agreement, dated September 27, 2024, by and between BKV Corporation and Banpu North America Corporation.	8-K	001-42282	10.2	9/27/24	
10.13†	BKV Corporation 2024 Equity and Incentive Compensation Plan (the "2024 Plan").	8-K	001-42282	10.3	9/27/24	
10.14†	Time Restricted Stock Unit Award Notice and Award Agreement under the 2024 Plan (CEO).	8-K	001-42282	10.4	9/27/24	
10.15†	Performance-Based Restricted Stock Unit Award Notice and Award Agreement under the 2024 Plan (CEO).	8-K	001-42282	10.5	9/27/24	
10.16†	Time Restricted Stock Unit Award Notice and Award Agreement under the 2024 Plan (Non-CEO Employee).	8-K	001-42282	10.6	9/27/24	
10.17†	Performance-Based Restricted Stock Unit Award Notice and Award Agreement under the 2024 Plan (Non-CEO Employee).	8-K	001-42282	10.7	9/27/24	
10.18†	Restricted Stock Unit Award Notice and Award Agreement under the 2024 Plan (Director).	8-K	001-42282	10.8	9/27/24	
10.19†	Form of Director and Officer Indemnity Agreement.	8-K	001-42282	10.9	9/27/24	
19.1	Insider Trading Policies and Procedures.					X
21.1	List of Subsidiaries of BKV Corporation.					X
23.1	Consent of PricewaterhouseCoopers LLP.					X
23.2	Consent of Ryder Scott Company, L.P.					X
31.1	Certification of Chief Executive Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2	Certification of Chief Financial Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
32.1	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X
32.2	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X
97.1	Clawback Policy of BKV Corporation.					X
99.1	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2024 (SEC Pricing) (Total Company Assets).					X
99.2	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2024 (NYMEX Pricing) (Total Company Assets).					X
101.INS	Inline XBRL Instance Document.					X
101.SCH	XBRL Taxonomy Extension Schema Document.					X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.					X
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.					X
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document.					X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.					X

104	Cover Page Interactive Data File (embedded within the inline XBRL document).	X

+ 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.

† Compensatory plan or arrangement

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

BKV CORPORATION

Date: March 31, 2025

By: /s/ John T. Jimenez
John T. Jimenez
Chief Financial Officer
(Principal Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of the registrant and 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)	March 31, 2025
/s/ John T. Jimenez John T. Jimenez	Chief Financial Officer (Principal Financial Officer)	March 31, 2025
/s/ Barry S. Turcotte Barry S. Turcotte	Chief Accounting Officer (Principal Accounting Officer)	March 31, 2025
/s/ Chanin Vongkusolkit Chanin Vongkusolkit	Chairman of the Board	March 31, 2025
/s/ Somruedee Chaimongkol Somruedee Chaimongkol	Director	March 31, 2025
/s/Joseph R. Davis Joseph R. Davis	Director	March 31, 2025
/s/ Akaraphong Dayananda Akaraphong Dayananda	Director	March 31, 2025
/s/ Kirana Limpaphayom Kirana Limpaphayom	Director	March 31, 2025

/s/ Carla S. Mashinski	Director	March 31, 2025
Carla S. Mashinski		
/s/ Thiti Mekavichai	Director	March 31, 2025
Thiti Mekavichai		
/s/ Charles C. Miller III	Director	March 31, 2025
Charles C. Miller III		
/s/ Sunit S. Patel	Director	March 31, 2025
Sunit S. Patel		
/s/Anon Sirisaengtaksin	Director	March 31, 2025
Anon Sirisaengtaksin		
/s/ Sinon Vongkusolkit	Director	March 31, 2025
Sinon Vongkusolkit		

Investor Information

STOCK EXCHANGE LISTING

New York Stock Exchange (NYSE): BKV

CORPORATE HEADQUARTERS

BKV Corporation
1200 17th Street, Ste. 2100
Denver, CO 80202
T: (720) 375-9680

Email: info@bkvcorp.com
Email: investorrelations@bkvcorp.com
For more information, please visit www.BKV.com

STOCK TRANSFER AGENT

Please direct general questions about shareholder accounts, stock certificates, transfer of shares or duplicate mailings to BKV Corporation transfer agent:

Broadridge Corporate Issuer Solutions, LLC
PO Box 1342
Brentwood, NY 11717
Telephone: 1-844-998-0339 (Toll Free),
303-562-9304 (International)

Email: shareholder@broadridge.com
Web Page: https://shareholder.broadridge.com/

ANNUAL MEETING

The 2025 Annual Meeting of Stockholders will be held virtually and in-person at 9:00 a.m. Central Daylight Time on Thursday, June 19, 2025. The in-person meeting will be held at the Ridglea Country Club, Ballroom, 3700 Bernie Anderson Ave., Fort Worth, TX 76116.

FORWARD-LOOKING STATEMENTS

This document contains forward-looking statements as defined by the Private Securities Litigation Reform Act of 1995. Forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from such forward-looking statements. For more information on these risks and uncertainties, please refer to "Risk Factors" and "Cautionary Note Regarding Forward-Looking Statements" within the Form 10-K included in this Annual Report.

BKV
LISTED
NYSE

BKV CORPORATION
1200 17TH STREET, STE. 2100
DENVER, CO 80202