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

# FORM 10-K/A

**(Amendment No. 1)**

**(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, 2025**

**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** | **80202** |
| **Denver, Colorado** | |
| (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 ☒

The aggregate market value of the registrant's voting and non-voting common stock held by non-affiliates of the registrant on June 30, 2025, the last business day of the registrant's most recently completed second fiscal quarter, computed by reference to the last sale price of the registrant's common stock as reported by the New York Stock Exchange on such date, was approximately $424.9 million. This computation assumes that all executive officers and directors are affiliates of the registrant. Such assumption should not be deemed conclusive for any other purpose.

The registrant had 102,288,077 shares of common stock outstanding as of February 27, 2026.

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 2026 Proxy Statement, filed within 120 days after the end of the fiscal year to which this Annual Report on Form 10-K relates.

**EXPLANATORY NOTE**

This Amendment No. 1 ("Amendment No. 1") to the Annual Report on Form 10-K of BKV Corporation ("BKV," the "Company," "our," "we," and "us") for the fiscal year ended December 31, 2025, as filed with the U.S. Securities and Exchange Commission (the "SEC") on March 6, 2026 (the "Original Form 10-K"), is being filed to replace the consent filed as Exhibit 23.1 to the Original Form 10-K, which inadvertently excluded references to the Company's effective Registration Statements on Form S-3 (Nos. 333-292408 and 333-290676), to amend the "Report of Independent Registered Public Accounting Firm" included in Item 8 of Part II "Financial Statements and Supplementary Data" of the Original Form 10-K (the "Audit Report") to include additional information in the "Basis for Opinion" section clarifying that the Company is not required to have, nor was PricewaterhouseCoopers LLP engaged to perform, an audit of the Company's internal control over financial reporting. Such change to the Audit Report does not affect PricewaterhouseCoopers LLP's unqualified opinion on the Company's consolidated financial statements as of December 31, 2025 and 2024, and for each of the three years in the period ended December 31, 2025 included in the Original Form 10-K, and to correct Management's certifications which inadvertently excluded the reference to the certifying officers' responsibility for establishing and maintaining internal control over financial reporting filed as Exhibits 31.1 and 31.2 to the Original Form 10-K.

In connection with the foregoing, the Company is also amending the Original Form 10-K to recast its financial statements as of December 31, 2025 and 2024, and for each of the three years in the period ended December 31, 2025 and related disclosures to retrospectively reflect an acquisition of a business between entities under common control in accordance with Accounting Standards Codification ("ASC") 805-50, *Business Combinations - Related Issues*, as well as to reflect a change in the Company's reportable segments, because the Company's Quarterly Reports on Form 10-Q for the period ended March 31, 2026, filed with the SEC on May 7, 2026 (the "Q1 2026 Form 10-Q") and for the period ended June 30, 2026, filed with the SEC on August 6, 2026 (the "Q2 2026 Form 10-Q") included recast historical financial statements and related disclosures for all periods included in the Q1 2026 Form 10-Q and Q2 2026 Form 10-Q. As previously disclosed, on January 30, 2026, the Company completed the acquisition of an additional 25% interest in BKV-BPP Power LLC (the "BKV-BPP Power Joint Venture Transaction") and, commencing in the first quarter of 2026, consolidated the financial results of BKV-BPP Power LLC into the Company's consolidated financial results. Because the BKV-BPP Power Joint Venture Transaction represented an acquisition of a business between entities under common control, the Company was required to retrospectively recast certain financial information and related disclosures included in the Q1 2026 Form 10-Q and Q2 2026 Form 10-Q to include the historical results of the BKV-BPP Power LLC for all periods during which the Company and BKV-BPP Power LLC were under common control. In addition, following the closing of the BKV-BPP Power Joint Venture Transaction, the Company's reportable segments changed from one reportable segment and one operating segment to two reportable segments, consisting of Upstream/Midstream and Power, and one operating segment, Corporate and Other, which is an "All Other" category that includes the Company's CCUS business.

Accordingly, this Amendment No. 1 amends and restates in their entirety Item 1 of Part I, "Business" and Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," Item 7A, "Quantitative and Qualitative Disclosures About Market Risk" and Item 8, "Financial Statements and Supplementary Data," of Part II of the Original Form 10-K to reflect the acquisition of a business between entities under common control and the change in the Company's reportable segments described above. See *Note 1 - Business and Basis of Presentation* and *Note 19 - Reportable Segments* to the Company's consolidated financial statements included herein for further information. Item 8 also includes the corrected Audit Report. This Amendment No. 1 also includes Item 9A in its entirety and without change from the Original Form 10-K.

Except as specifically set forth herein, this Amendment No. 1 does not modify or update in any way the disclosure in, or exhibits to, the Original Form 10-K, and the Company has not updated disclosures contained therein to reflect any events that occurred at a date subsequent to the date of the filing of the Original Form 10-K. Accordingly, this Amendment No. 1 should be read in conjunction with the Original Form 10-K and the Company's other filings with the SEC. Certain capitalized terms used and not otherwise defined in this Amendment No. 1 have the meanings given to them in the Original Form 10-K.

Pursuant to Rule 12b-15 under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), we have included the entire text of Part II, Item 9A, "Controls and Procedures" and Item 15 "Exhibits and Financial Statement Schedules" of the Original Form 10-K in this Amendment No. 1, and this Amendment No. 1 also contains new certifications pursuant to Section 302 and 906 of the Sarbanes-Oxley Act of 2002, which are being filed as Exhibits 31.1, 31.2, 32.1 and 32.2 hereto, respectively.

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## CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Amendment No. 1 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 Amendment No. 1 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 Amendment No. 1, 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. Such forward-looking statements include those described in “Item 1A. *Risk Factors*” to the Original Form 10-K, as well as the following factors, among others: statements about the anticipated benefits, opportunities and results with respect to the BKV-BPP Power Joint Venture Transaction and the Bedrock Acquisition, including any expected value creation from the BKV-BPP Power Joint Venture Transaction, or the Bedrock Acquisition, and any reserves, additions, midstream opportunities, and other anticipated impacts from the Bedrock Acquisition, anticipated efficiencies, power plant reliability, and strategic growth and power purchase agreement opportunities relating to the BKV-BPP Power Joint Venture and the BKV-BPP Power Joint Venture Transaction, as well as guidance, projected or forecasted financial and operating results, future liquidity, leverage, results in certain basins, objectives, project timing, expectations and intentions, regulatory and governmental actions, and other statements that are not historical facts. 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 Amendment No. 1 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 our sponsor, Banpu and its affiliates, 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;
- changes in trade regulation, including tariffs and other market factors;
- legal, regulatory, or environmental matters;
- marketing of natural gas, NGL, and oil;
- business or leasehold acquisitions and integration of acquired businesses, including the Bedrock Acquisition, with our business;
- 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 $CO_2$ 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;
- 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 weakness;
- the Bedrock Acquisition and the anticipated benefits thereof;
- the BKV-BPP Power Joint Venture Transaction and the anticipated benefits thereof;
- the impact of the One Big Beautiful Bill Act of 2025 (the “OBBBA”); and
- our plans, objectives, expectations, and intentions.

Although we believe our estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management’s assumptions about future events may prove to be inaccurate. Management cautions all readers that the forward-looking statements contained in the Original Form 10-K and this Amendment No. 1 are not guarantees of future performance, and we cannot assure any reader that those statements will be realized or the forward-looking events and circumstances will occur.

Undue reliance should not be placed on any forward-looking statements, which are based on predictions of future results, which may not occur as anticipated. Actual results could differ materially from those anticipated in the forward-looking statements and from historical results, due to the risks and uncertainties described above, as well as others not now anticipated. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors. The foregoing statements are not exclusive and further information concerning us, including factors that potentially could materially affect our financial results, may emerge from time to time. We undertake no obligation to update forward-looking statements to reflect actual results or changes in factors or assumptions affecting such forward-looking statements, except as required by law, including the securities laws of the United States and the rules and regulations of the SEC.

# 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 long-term risk-adjusted stockholder value through the development of natural gas producing assets, the ownership and operation of natural gas-fired power generation assets, and selective accretive acquisitions. Our core businesses are the production of natural gas and the generation of natural gas-fired power from our owned and operated assets, supported by a closed-loop strategy enabled by our upstream, midstream, power, and CCUS businesses.

On January 30, 2026, we completed the previously announced acquisition of an additional 25% interest in the BKV-BPP Power Joint Venture pursuant to the BKV-BPP Power Purchase Agreement (the "BKV-BPP Power Joint Venture Transaction"). Following the closing of this transaction, the BKV-BPP Power Joint Venture is owned 75% by BKV Corp and 25% by BPPUS and, effective as of the first quarter of 2026, our reportable segments changed from one reportable segment and one operating segment to two reportable segments, consisting of Upstream/Midstream and Power and one operating segment, consisting of Corporate and Other, which is an "All Other" category that includes our CCUS business. Accordingly, prior period segment information has also been retrospectively recast to reflect the current reportable segment presentation. See *Note 19 - Reportable Segments* to our consolidated financial statements for further information.

Our operations are supported by four business lines: natural gas production, natural gas midstream, power generation, and CCUS. Our operating approach is designed around a closed-loop model that aligns these business lines to support cost efficiency, commercial optimization, and operational reliability across the value chain. Through this approach, we retain operational control over the production, transportation, and processing of natural gas and provide multiple platforms for disciplined capital deployment, while meeting growing demand for low carbon natural gas and power.

For example, in the Barnett Shale, natural gas produced from our upstream assets is gathered and transported in part through our midstream systems. In November 2023, we commenced sequestration operations at our first CCUS project, and we currently expect our second and third CCUS projects to commence sequestration activities during the first and second quarter of 2026 with additional CCUS growth opportunities beyond 2026. Our Power segment consists of the BKV-BPP Power Joint Venture's electricity generation, wholesale energy sales and purchases, and retail marketing operations.

As part of our ongoing operations, we expect our owned and operated upstream and natural gas midstream businesses to achieve net-zero Scope 1 and Scope 2 greenhouse gas emissions during the early 2030s and net-zero Scope 1, Scope 2, and Scope 3 emissions by the late 2030s.

We believe our business model, experienced management team, and disciplined technology-enabled operations support our ability to create long-term, risk-adjusted stockholder value.

### 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 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 across all four of our business lines, 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. In our upstream and midstream 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. In our power business, the Temple Plants utilize modern, combined-cycle technology that enables real-time response to market signals, maximizing generation during peak demand periods and optimizing fuel efficiency. By combining our reserves into a growing asset base with vertically integrated components that span upstream production through power generation, 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. We intend to continue to build out our power generation business and expand into additional power markets and retail electricity opportunities.

**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, multiple integrated business lines, and the cash flows generated by our power generation operations 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. The development of our power business is capital intensive, requiring ongoing investments in land, modular generation equipment, and turbine generators, and its continued growth is dependent on access to capital and the ability to obtain necessary commercial agreements, including power purchase agreements.

**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 during 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, emissions monitoring and leak surveys, the retirement of SRECs generated by the BKV-BPP Power Joint Venture’s solar facility, and executing CCUS projects. Additionally, we are processing FEED studies regarding $CO_2$ capture from combined-cycle natural gas power turbines, like those at the Temple Plants, which, if implemented, would significantly reduce the carbon intensity of our power generation operations. 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, natural gas midstream, and gas-fired power generation businesses, CCUS for third parties is 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, as well as our commercial and operational optimization of the Temple Plants in the ERCOT market. 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, operating highly efficient power generation facilities, 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, 2025, our total acreage position was approximately 563,000 net acres, substantially all of which was held by production. For the year ended December 31, 2025, our net daily production (after giving effect to the Bedrock Acquisition) averaged 835.5 MMcfe/d, consisting of approximately 80% natural gas and approximately 20% NGLs. As of December 31, 2025, our total proved reserves of 5,921 Bcfe had an estimated 7.4% year-over-year average base decline rate over the next 10 years.

As of December 31, 2025, our Barnett acreage position was approximately 544,000 net acres, substantially all of which was held by production. Our average daily Barnett production of approximately 742.0 MMcfe/d for the year ended December 31, 2025 consisted of approximately 77% natural gas and approximately 23% NGLs. We had an average working interest in our operated wells in the Barnett of approximately 96.5% as of December 31, 2025 and an Effective NRI in the Barnett of approximately 80.2%. As of December 31, 2025, our NEPA acreage position was approximately 19,100 net acres, 97.0% of which was held by production. Our average net daily production of 93.6 MMcfe/d for the year ended December 31, 2025 consisted entirely of natural gas. As of December 31, 2025, we had an average working interest in our operated wells in NEPA of 87.8%.

On September 29, 2025, BKV Upstream Midstream acquired 100% of the equity interests of Bedrock Production, LLC (now known as BKV Barnett II, LLC ("BKV Barnett II")), a Texas limited liability company (such transaction, the "Bedrock Acquisition"). BKV Barnett II and its subsidiaries own certain oil and natural gas producing properties and midstream assets in the Barnett Shale. As a result of the Bedrock Acquisition, we acquired approximately 96,000 net acres and gas gathering lines, 1,121 producing locations with low 1- and 5-year base decline rates of approximately 7%, and nearly 1 Tcfe of proved reserves (>70% PDP reserves) using NYMEX strip pricing. The Bedrock Acquisition is expected to increase our production over 100 MMcfe/d and enhance our inventory in the Barnett Shale, aligning with our strategic position in the Fort Worth Basin.

*Certification and Market Positioning***.** As of December 31, 2025, we re-certified approximately 72% of our NEPA production and 46% 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 or Silver rating from Project Canary. Since our initial certification in 2021, the RSG market has not materialized, and during 2026, Project Canary will be closing down its TrustWell program. We may seek to certify our production against the MiQ Standard and/or align with the Oil & Gas Methane Partnership 2.0 (OGMP 2.0) of the United Nations ("UN") Environment Programme. Because there has yet to be a U.S. domestic standard for certification, we intend to position ourselves for a variety of competitive landscapes to promote market access and advance our own market for low carbon, and carbon neutral gas products by utilizing our "Carbon Sequestered Gas," which is a Scope 1, 2, and 3 carbon neutral natural gas product.

*Carbon Sequestered Gas***.** We expect that production of Carbon Sequestered Gas will be achieved by bundling our low carbon intensity produced natural gas with carbon credits sufficient to offset the estimated emissions associated with the production, gathering, and boosting of such gas, 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 for carbon offset produced natural gas developed by existing carbon registries such as ACR (formerly American Carbon Registry) or Verra, as those methodologies are currently being 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.

We have 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).

In August 2025, BKV entered into a deal with Gunvor Group, Ltd. (“Gunvor”), a leading commodities trader for Carbon Sequestered Gas. This deal covers up to 10,000 MMBtu/d and allows Gunvor to purchase, market, and sell this premium commodity market product.

***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. Our midstream operations also support the reliable delivery of natural gas fuel to the Temple Plants through our firm transportation arrangements into the Katy, Texas area and other delivery points.

**Barnett**

In the Barnett, during the year ended December 31, 2025, approximately 202 MMcf/d of our gross production (approximately 20% of our total gross Barnett production) was gathered and processed by our owned Barnett midstream system, which includes approximately 870 miles of gathering pipeline, 61 midstream compressors, and one amine processing unit. Our remaining Barnett production was gathered and processed primarily under an agreement with ONEOK (formerly EnLink) with no minimum volume commitments (“MVC”).

For the assets we acquired in the Bedrock Acquisition, the substantial majority of our natural gas is gathered and transported by third parties, with less than 5% gathered and transported by us. 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. For the assets we acquired in the Devon Barnett Acquisition, approximately 95% of our natural gas is gathered and transported by ONEOK 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 ONEOK 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 ten gas compression units in NEPA. As part of our sale of 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 third-party providers. For the year ended December 31, 2025, approximately 52%, 41%, and 7% of our gross operated volumes in NEPA were further gathered, treated, and transported to sales on the gathering systems of UGI Energy Services Midstream Services, Williams Companies, and Energy Transfer, 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, 2025, 82 MMcf/d of MVC related to the gathering, central delivery point aggregation, and intra-basin transport.

The terms of these contracts range from 10 to 20 years from the original execution date, with an average term of three years remaining between the various contracts, as of December 31, 2025. 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***

Our Power segment consists of the BKV-BPP Power Joint Venture's electricity generation, wholesale energy sales and purchases, and retail marketing operations. The BKV-BPP Power Joint Venture owns the Temple Plants, which are modern combined-cycle gas and steam turbine power plants located in the ERCOT North Zone in Temple, Texas. Prior to January 30, 2026, we owned a 50% interest in the BKV-BPP Power Joint Venture. Upon closing, we acquired an additional 25% interest from BPPUS, increasing our ownership to 75%. Because the transaction was between entities under common control, the accompanying consolidated financial statements have been retrospectively recast to reflect the acquisition as if it had occurred for all periods during which the entities were under common control.

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 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. The table presents the power generated from the Temple Plants and their capacity factors:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| Generation (GWh) | 7,611 | 7,360 | 7,230 |
| Capacity Factor Temple I | 59.2 % | 58.1 % | 57.4 % |
| Capacity Factor Temple II | 58.7 % | 55.1 % | 54.4 % |

*Natural Gas Supply*. The Temple Plants are fueled by natural gas sourced primarily from the Houston Ship Channel and Katy area markets. The BKV-BPP Power Joint Venture holds a combined 200,000 MMBtu/d of firm transportation with Atmos and Energy Transfer and their subsidiaries, which supports receipt of gas from the Katy area with delivery to the Temple facility. Additionally, Temple I holds 125,000 MMBtu/d of interruptible transportation with Atmos Pipeline for delivery to Temple I. The BKV-BPP Power Joint Venture also holds 2,812,500 MMBtu of storage at Energy Transfer's Bammel storage facility. This integration between our upstream natural gas production and the fuel requirements of the Temple Plants is a key component of our closed-loop business model.

*Retail Marketing*. 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. As of December 31, 2025, BKV Energy has a portfolio of over 58,000 customers and is licensed to serve throughout the deregulated portions of Texas. BKV Energy generates revenues primarily through retail customer contracts and purchases power in the wholesale ERCOT market to satisfy its retail obligations.

*Power Growth Strategy*. We are actively pursuing a power growth strategy designed to expand our power generation capacity and deepen the integration between our upstream natural gas production and downstream power generation capabilities. As part of this strategy, on January 14, 2026, we entered into a manufacturing reservation agreement related to a planned power generation project under which we are committed to pay up to an aggregate of $80.0 million in reservation fees to secure future manufacturing capacity through 2028 for turbines with up to approximately 1,230 MW in total generation capacity. 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.

***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 and Verra 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 during 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 ability 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 the majority of our CCUS business from a variety of external sources, including contributions from our joint ventures with the Class B Member and BPPUS, project-based equity partnerships, debt financing, and federal grants, with the remaining capital needs being funded with cash flows from operations. The projected timeline for commercial operations and the generation of positive CCUS business revenue and positive earnings depends, in part, on our ability to fund the anticipated capital requirements for the potential projects that we have identified and described below through external funding and revenues from our upstream business, as well as on our ability to receive our portion of the anticipated Section 45Q tax credits associated with these projects. For CCUS facilities placed in service after December 31, 2022, Section 45Q of the Code generally provides the capturing parties a tax credit of $85.00 per ton for $CO_2$ directly stored in geologic formations, subject to satisfaction or non-application of certain prevailing wage and apprenticeship requirements (or $17.00 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, we will receive a certain fee for $CO_2$ transportation and/or sequestration services we provide for such projects, or we will receive only a corresponding percentage of the anticipated Section 45Q tax credits associated with such projects.

**CCUS Projects**

On May 8, 2025, BKV dCarbon Ventures, together with the Class B Member, and for the limited purposes specified therein, BKV Corporation, entered into the BKV-CIP JV Agreement forming BKV dCarbon Project, LLC (the "BKV-CIP Joint Venture") for the purpose of developing CCUS projects. On May 8, 2025, BKV dCarbon Ventures contributed to the BKV-CIP Joint Venture $40.3 million of CCUS assets that included BKV dCarbon Barnett Zero, LLC and BKV dCarbon Las Tiendas, LLC and related assets (including the Barnett Zero and Eagle Ford CCUS projects), and $4.1 million of Section 45Q accrued receivables at carrying value, and committed to future contributions of certain CCUS projects, related assets, and/or cash in exchange for an interest in the BKV-CIP Joint Venture and 4,796,421 Class A Units at $10.00 per share. The Class B Member committed up to an initial $500.0 million in cash for use by the BKV-CIP Joint Venture in construction and operating new CCUS projects across the U.S. in exchange for no more than a 49% interest in the BKV-CIP Joint Venture. As of December 31, 2025, the Class B Member contributed $17.9 million.

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. 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 projects can be placed into two categories: (i) Class II (NGP) projects and (ii) Class VI projects. The table below presents actual and forecasted quantities of active sequestration operations for each category for years 2025 through 2028 and the early 2030s.

| **Project Category [1] [2]** | **YE 2025 Actual Gross Rate (Mtpy $CO_2$)** | **YE 2026 Forecasted Gross Rate (Mtpy $CO_2$)** | **YE 2027 Forecasted Gross Rate (Mtpy $CO_2$) [3]** | **YE 2028 Forecasted Gross Rate (Mtpy $CO_2$) [3]** | **Early 2030s Forecasted Gross Rate (Mtpy $CO_2$) [3]** |
|---|---|---|---|---|---|
| Class II | 0.1 | 0.2 | 0.4 | 1.3 | 2.1 |
| Class VI | — | — | — | 0.2 | 16.9 |
| Total | 0.1 | 0.2 | 0.4 | 1.5 | 19.0 |

(1) Our projected timeline for commencement of sequestration operations for the project categories 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*" in the Original Form 10-K.

(2) 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 ability 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.

(3) We have not secured external financing, reached FID, or entered into the definitive agreements necessary to execute many of the projects contributing to the YE 2027, YE 2028, and Early 2030s Forecasted Gross Rates above.

However, we have not secured external financing, reached FID, or entered into the definitive agreements necessary to execute many of the projects contributing to the YE 2027, YE 2028, and Early 2030s Forecast Gross Rates identified above, and there can be no guarantee that we will be able to execute and operate any of these potential future CCUS projects (or any other CCUS projects) with sufficient volumes of $CO_2$ sequestration to achieve our Scope 1, 2, and 3 emissions goals on the timelines we anticipate. There can be no assurance that these potential CCUS projects, the projects further described herein, 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 our joint venture partners, owners of sources of $CO_2$, landowners, and other stakeholders. In order to achieve the projected timeline for commercial operations of such projects, we expect to fund the majority of the anticipated cost of these CCUS projects from third-party sources, including contributions from our joint ventures with the Class B Member and BPPUS, project-based equity partnerships, debt financing, 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.

We have achieved notable milestones with respect to certain projects within each category, as more fully described below.

**Class II 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 ONEOK's Bridgeport natural gas processing plant and neighboring operations. In the Barnett Zero Project, ONEOK 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 2025, our operational projects achieved a total sequestration of approximately 138,000 metric tons of $CO_2$.

We have used and intend to continue 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 and initiate sequestration operations at various points in 2026 through 2028.

**Class II FID Projects**

*Eagle Ford Project*. On December 18, 2024, BKV dCarbon Ventures reached internal FID to develop our second CCUS project for the sequestration of $CO_2$ waste generated by 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 $CO_2$ per year. We currently estimate the total investment required for the Eagle Ford Project to be approximately $22 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 during the first quarter of 2026, at which point we expect this project will be the second of our current modular line of identified potential NGP projects.

*Cotton Cove Project*. On October 18, 2022, BKV dCarbon Ventures reached internal FID to develop our third 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 secured pore space 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 $18.0 million, of which we contributed $9.0 million and BPPUS contributed $8.8 million through December 31, 2025. 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 during the first half of 2026, 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 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.

*East Texas Project*. On December 11, 2025, BKV dCarbon Ventures reached internal FID to develop our fourth CCUS project for the sequestration of waste emissions from a natural gas processing plant. This CCUS project, which we refer to as the East Texas 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 East Texas Project will geologically sequester up to approximately 70,000 metric tons of $CO_2$ per year. We currently estimate the total investment required for the East Texas Project to be approximately $22 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 2027, at which point we expect this project will be the fourth of our current modular line of identified potential NGP projects.

**Other Class II 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 2028. Much of the carbon capture infrastructure required for these NGP projects is already in place. For example, the NGP facilities have amine towers to capture and concentrate $CO_2$ emissions to meet natural gas sales specifications. Also, we have secured or are in discussions to secure definitive agreements for pore space leasehold for several projects, and have submitted or are working towards submitting well permit applications. If these projects are approved at FID, definitive agreements are executed on the terms and timeline we believe are obtainable, and sufficient external funding is secured, we expect these projects to start sequestration operations before December 31, 2028.

On February 24, 2026, BKV dCarbon Ventures entered into a definitive agreement in connection with our fifth and sixth CCUS projects for the sequestration of waste emissions from natural gas processing plants. We expect these CCUS projects to capture, compress, and then dispose of and geologically sequester the $CO_2$ waste stream generated as a byproduct of Comstock Resource's natural gas processing plants in the Western Haynesville region. Although we have not secured external financing, reached FID, or entered into all definitive agreements necessary to execute these projects we have identified, if approved at FID, assuming we are able to execute additional definitive agreements on the terms and timeline we believe are obtainable, and secure sufficient external funding, and subject to receipt of required regulatory approvals, these projects are expected to include the development of two Class II injection wells and further expand our current modular line of identified potential NGP projects. For more information about the risks involved in our CCUS business, see "*Risk Factors - Risks Related to Our CCUS Business*" in the Original Form 10-K.

**Class VI Projects**

We are also 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 prior to 2033.

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 10 Mtpy $CO_2$ of potential capture and sequestration in Phase I of the development. This site is located within a 20 mile radius from various emissions points. The Class VI permit application for Phase I of the initial five well development was submitted on March 31, 2025, and was deemed administratively complete on August 27, 2025 by the Louisiana Department of Energy and Natural Resources (now the Louisiana Department of Conservation and Energy). The storage site is estimated to have approximately 200 Mt of total $CO_2$ storage capacity in Phase I of the development, which is expected to support injection volumes of up to 10 Mt per year over an anticipated operating life of approximately 20 years. Additional phases of development may be undertaken as needed. We currently estimate the total investment required for High West to be approximately $163 million with the potential for additional phases of development. Under the agreement, High West will dispose of $CO_2$ 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 three of these industrial projects, two of which are in the State of Louisiana and one of which is in the State of Texas. The U.S. Environmental Protection Agency (the "EPA") recognized our permit applications as being administratively complete in January 2024 and February 2024, respectively, for one of our State of Louisiana projects and the State of Texas project. Both the State of Louisiana and State of Texas applied for, and have been granted, primacy for the EPA's Class VI permitting program and these two applications have been transferred from the EPA to the respective state agencies. In July 2025, the Louisiana Department of Conservation and Energy additionally recognized the permit application originally submitted to the EPA for the State of Louisiana permit as administratively complete. For the other State of Louisiana Class VI location (which BKV has designated as the "High West" project), the Class VI permit application for a five well initial development industrial location was filed with the State of Louisiana on March 31, 2025. On August 27, 2025, the Louisiana Department of Conservation and Energy recognized the initial five well permit applications as being administratively complete. We continue to engage in discussions with additional $CO_2$ sources regarding a number of potential projects. Subject to FID for each project, the availability of sufficient external financing, and the execution of definitive agreements we believe are obtainable, we expect to initiate sequestration operations prior to 2033.

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, reached FID, and entered into definitive agreements with respect to the Eagle Ford Project, the Cotton Cove Project, and the East Texas Project, we have not reached FID for, 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 the majority of these CCUS projects from a variety of external sources, including contributions from our joint ventures with the Class B Member and BPPUS, project-based equity partnerships, debt financing, and federal grants, with the remaining capital needs being funded with cash flows from operations. 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*" in the Original Form 10-K.

As discussed above, we are also currently progressing FEED studies regarding $CO_2$ capture from combined-cycle natural gas power turbines, like those at the Temple Plants, to further delineate capital and operating costs of such facilities. Implementation of such capture at BKV's existing or developed power facilities would significantly reduce the carbon intensity of the associated power produced from such facilities.

***Path to Net Zero Emissions***

We conducted an initial assessment of our annual Scope 1 and 2 emissions from our owned and operated 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 Amendment No. 1 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 2024 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 17.0 Mtpy $CO_2$ as of December 31, 2024. 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 for Category 11 represent over 90% of the 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. Effective as of 2024, the Company's Scope 3 $CO_{2e}$ emissions are estimated using AR5 Global Warming Potentials, similar to those used by the EPA. The AR5 Global Warming Potentials supersede the AR4 Global Warming Potentials applied in prior periods. Our annual Scope 3 $CO_{2e}$ emissions for the year ended December 31, 2024 were estimated at an approximated year-end net production volume of 855 MMcfe/d of natural gas (approximately 85% methane, 5% ethane and 10% other) and approximately 113.4 MBbls of NGLs (or approximately 1.7 MMcfe/d), as reported to the EPA for Subpart W. Our NGL constituents are estimated based on average constituent NGL barrel. Allocating the entire 856 MMcfe/d towards combustion as the end use, applying suitable combustion emission factors from the EPA, and using AR5 GWPs, Scope 3 annual emissions from our operated upstream operations are estimated at approximately 17.0 Mtpy $CO_2$. 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 has implemented pad level design improvements to reduce pad level usage of natural gas, reduce GHG emissions, and maintain operational continuity. As of December 31, 2025, we completed the conversion of over 75% of our pneumatic devices and pneumatic pumps in the Barnett and during the year ended December 31, 2025, we successfully completed the program with our upstream owned and operated assets in NEPA. Through December 31, 2025, our total costs incurred to complete the conversions approximated $23.6 million.

Based on the success of this effort, methane is no longer our largest source of GHG emissions on a $CO_{2e}$ emissions-related basis. Due to this success, regulatory updates, and other operational efficiencies, we are evaluating the need for future pneumatic retrofits and will be transitioning investments to other emission reduction technologies more impactful to our assets.

*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. The initial 2.5 MW phase was completed and began generating power in August 2024. The BKV-BPP Power Joint Venture has obtained permits for the full 5 MW facility and is evaluating development 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 approximately 30% of the Scope 2 emissions from our owned and operated upstream and natural gas midstream business as of December 31, 2025.

*CCUS*. Further, as discussed under "— *Carbon Capture, Utilization, and Sequestration*" above, we believe that the Barnett Zero Project, together with the Eagle Ford Project, the Cotton Cove Project, the East Texas 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 19.0 Mtpy $CO_2$ during 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 $CO_2$ 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 and natural gas midstream businesses during 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 17.0 Mtpy $CO_2$ annually as of December 31, 2024. Our CCUS business of capturing and sequestering our gas processing-related emissions along with third-party GHG 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 primarily 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. We will periodically perform materiality assessments on our Scope 3 emissions to ensure the accuracy of our Scope 3 emissions footprint. At this time, 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 owned by the BKV-CIP Joint Venture 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 19.0 Mtpy $CO_2$ during 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. The BKV-CIP Joint Venture will retain and monetize all environmental attributes associated with CCUS projects contributed to the BKV-CIP Joint Venture, including pursuant to a first right of BKV or its affiliates to purchase such environmental attributes at fair market value. Ultimately, with respect to CCUS projects contributed to the BKV-CIP Joint Venture, we will be able to apply to offset our own GHG emissions only the portion of sequestered emissions attributable to the percentage of environmental attributes that BKV purchases from the BKV-CIP Joint Venture. 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 purchase, 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 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. 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, 2025:

| | Developed | | Undeveloped | | Total | |
|---|---|---|---|---|---|---|
| **Operating Region** | **Gross** | **Net** | **Gross** | **Net** | **Gross** | **Net** |
| Barnett [(1)] | 760,746 | 504,815 | 48,330 | 39,214 | 809,076 | 544,029 |
| NEPA | 21,677 | 18,312 | 1,467 | 785 | 23,144 | 19,097 |
| Total | 782,423 | 523,127 | 49,797 | 39,999 | 832,220 | 563,126 |

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 |

(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 0.93% in 2026, 1.14% in 2027, and 0.64% in 2028.

**Our Productive Wells**

The following table sets forth our gross and net productive natural gas and oil wells as of December 31, 2025:

| | Producing Natural Gas Wells | | Producing Oil Wells | | Total | | Average Working Interest |
|---|---|---|---|---|---|---|---|
| **Operated Wells** | **Gross** | **Net** | **Gross** | **Net** | **Gross** | **Net** | **Interest** |
| Barnett | 6,357 | 6,132 | 10 | 10 | 6,367 | 6,142 | 96.5 % |
| NEPA | 147 | 129 | — | — | 147 | 129 | 87.8 % |
| Total | 6,504 | 6,261 | 10 | 10 | 6,514 | 6,271 | 96.3 % |
| **Non-Operated Wells** | | | | | | | |
| Barnett | 927 | 89 | 7 | 1 | 934 | 90 | 9.6 % |
| NEPA | 36 | 1 | — | — | 36 | 1 | 2.8 % |
| Total | 963 | 90 | 7 | 1 | 970 | 91 | 9.4 % |
| **Total** | | | | | | | |
| Barnett | 7,284 | 6,221 | 17 | 11 | 7,301 | 6,232 | 85.4 % |
| NEPA | 183 | 130 | — | — | 183 | 130 | 71.0 % |
| Total | 7,467 | 6,351 | 17 | 11 | 7,484 | 6,362 | 85.0 % |

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

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

| | Producing Natural Gas Wells | | Producing Oil Wells | | Total | | Average Working Interest |
|---|---|---|---|---|---|---|---|
| **Operated Wells** | **Gross** | **Net** | **Gross** | **Net** | **Gross** | **Net** | **Interest** |
| 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 % |

**Drilling, Refrac, and Restimulation Activity**

During the years ended December 31, 2025, 2024, and 2023, we drilled development wells as set forth in the table below:

| | 2025 | | 2024 | | 2023 | |
|---|---|---|---|---|---|---|
| **Development** | **Gross** | **Net** | **Gross** | **Net** | **Gross** | **Net** |
| Barnett | | | | | | |
| Productive | 33.0 | 33.0 | 6.0 | 6.0 | 15.0 | 15.0 |
| Dry | 1.0 | 0.9 | — | — | — | — |
| NEPA | | | | | | |
| Productive | 4.0 | 4.0 | — | — | 3.0 | 3.0 |
| Dry | — | — | — | — | — | — |
| Total | 38.0 | 37.9 | 6.0 | 6.0 | 18.0 | 18.0 |

As of December 31, 2025, we had four wells (4.0 net) drilled and uncompleted in the Barnett and three wells (3.0 net) drilled and uncompleted in NEPA. In addition, we had one well (1.0 net) in the process of being drilled in the Barnett, and none in NEPA. During the year ended December 31, 2025, 35 wells (34.9 net) were completed in the Barnett, which included two previously drilled but uncompleted wells that were acquired in the Bedrock Acquisition, and one well was completed in NEPA, all of which were net productive. All drilled and uncompleted wells from prior year programs had been completed and placed into production as of December 31, 2025.

As of December 31, 2024, we had four wells (4.0 net) drilled and uncompleted in the Barnett and no wells drilled and uncompleted in NEPA. During the year ended December 31, 2024, ten wells were completed in the Barnett and three wells were completed in NEPA, all of which were net productive. All drilled and uncompleted wells from prior year programs had been completed and placed into production as of December 31, 2024.

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.

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, 2025, 2024, and 2023, we completed 56, three, and 32 horizontal and vertical restimulations, respectively. Additionally, as of December 31, 2025, we had 209 proved undeveloped horizontal locations and 323 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, 2025, 2024, and 2023.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| **Production Volumes** | | | |
| ***Barnett*** | | | |
| Natural gas (MMcf) | 208,779.7 | 185,857.3 | 198,099.4 |
| Natural gas liquids (MBbl) | 10,181.4 | 9,857.7 | 10,553.6 |
| Oil (MBbl) | 159.3 | 96.0 | 118.6 |
| Total Barnett (Bcfe) | 270.8 | 245.6 | 262.1 |
| ***NEPA*** | | | |
| Natural gas (MMcf) | 34,151.7 | 42,825.3 | 51,666.9 |
| Natural gas liquids (MBbl) | — | — | — |
| Oil (MBbl) | — | — | — |
| Total NEPA (Bcfe) | 34.2 | 42.8 | 51.7 |
| Total Company (Bcfe) | 305.0 | 288.4 | 313.8 |
| **Average Sales Prices (excluding impact of derivative settlements)** | | | |
| ***Barnett*** | | | |
| Natural gas ($/Mcf) | $ 2.91 | $ 1.87 | $ 2.28 |
| Natural gas liquids ($/Bbl) | $ 17.00 | $ 16.79 | $ 17.80 |
| Oil ($/Bbl) | $ 59.38 | $ 68.81 | $ 71.21 |
| ***NEPA*** | | | |
| Natural gas ($/Mcf) | $ 1.98 | $ 0.91 | $ 1.12 |
| Natural gas liquids ($/Bbl) | $ — | $ — | $ — |
| Oil ($/Bbl) | $ — | $ — | $ — |
| Total Company ($/Mcfe) | $ 2.81 | $ 1.93 | $ 2.25 |
| **Average Sales Prices (including the impact of derivative prices)** (1) | | | |
| Natural gas ($/Mcf) | $ 2.75 | $ 2.10 | $ 2.23 |
| Natural gas liquids ($/Bbl) | $ 16.84 | $ 17.19 | $ 17.55 |
| Oil ($/Bbl) | $ 59.50 | $ 68.81 | $ 70.97 |
| Total Company ($/Mcfe) | $ 2.79 | $ 2.28 | $ 2.39 |
| **Average Production Cost ($/Mcfe)** (2) | | | |
| Barnett | $ 1.45 | $ 1.43 | $ 1.48 |
| NEPA | $ 0.29 | $ 0.20 | $ 0.24 |
| Total Company | $ 1.32 | $ 1.25 | $ 1.27 |

(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.

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

**Determination of Identified Drilling and Refracture Locations**

***Proved Drilling and Refracture Locations***

As of December 31, 2025, we had approximately 209 gross (191 net) proved undeveloped horizontal drilling locations and 323 gross (305 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, 2025, 2024, and 2023. 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 were filed as exhibits to the Original Form 10-K.

The following table provides our estimated proved reserves information prepared by Ryder Scott as of December 31, 2025, 2024, and 2023 and PV-10 Value and the Standardized Measure for each period. The increase in our proved reserves and the PV-10 Value of those reserves as of December 31, 2025, as compared to December 31, 2024, is primarily due to higher commodity pricing. 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, was 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, | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| **Estimated proved developed reserves:** | | | |
| Natural gas (MMcf) | 3,097,864 | 2,059,983 | 2,443,072 |
| Producing | 2,913,523 | 1,951,321 | 2,290,025 |
| Non-producing | 184,341 | 108,662 | 153,047 |
| Natural gas liquids (MBbls) | 183,111 | 134,016 | 156,399 |
| Producing | 162,684 | 113,738 | 129,260 |
| Non-producing | 20,427 | 20,278 | 27,139 |
| Oil (MBbls) | 1,763 | 878 | 992 |
| Producing | 1,600 | 713 | 802 |
| Non-producing | 163 | 165 | 190 |
| Total estimated proved developed reserves (MMcfe) | 4,207,108 | 2,869,347 | 3,387,418 |
| Producing | 3,899,227 | 2,638,027 | 3,070,397 |
| Non-producing | 307,881 | 231,320 | 317,021 |
| **Estimated proved undeveloped reserves:** | | | |
| Natural gas (MMcf) | 1,247,900 | 176,047 | 539,423 |
| Natural gas liquids (MBbls) | 75,545 | 13,605 | 27,766 |
| Oil (MBbls) | 2,118 | 813 | 59 |
| Total estimated proved undeveloped reserves (MMcfe) [2], [3] | 1,713,878 | 262,555 | 706,373 |
| **Estimated total proved reserves:** | | | |
| Natural gas (MMcf) | 4,345,764 | 2,236,030 | 2,982,495 |
| Natural gas liquids (MBbls) | 258,656 | 147,621 | 184,165 |
| Oil (MBbls) | 3,881 | 1,691 | 1,051 |
| Total estimated proved reserves (MMcfe) | 5,920,986 | 3,131,902 | 4,093,791 |
| Standardized Measure (millions) | $ 2,345 | $ 633 | $ 1,062 |
| PV-10 (millions) [4], [5] | $ 2,788 | $ 672 | $ 1,232 |

(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, 2025 were $3.39 per MMBtu (Henry Hub), $65.34 per Bbl (WTI Cushing), and NGL pricing equal to 34.4% of

WTI Cushing, (ii) 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, and (iii) 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.

(2) Proved undeveloped reserves as of December 31, 2025, 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.

(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, 2025, 2024, and 2023:

| | December 31, | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| PV-10 (millions) | $ 2,788 | $ 672 | $ 1,232 |
| Present value of future income taxes discounted at 10% | (443) | (39) | (170) |
| Standardized Measure | $ 2,345 | $ 633 | $ 1,062 |

During the years ended December 31, 2025, 2024, and 2023, we incurred costs of approximately $140.0 million, $22.8 million, and $37.7 million, respectively, to convert 157.9 Bcfe, 57.6 Bcfe, and 31.9 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, 2025, 2024, and 2023, were approximately $1.0 billion, $135.1 million, and $360.7 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, 2025 focused on refracturing under-stimulated wells and designing and drilling new wells in the Barnett, and designing, completing, and drilling new wells in NEPA. Our proved undeveloped reserves, as of December 31, 2025, are scheduled to be developed within five years of their initial disclosure.

***2025 Activity***

During the year ended December 31, 2025, our proved reserves increased by 2,789.1 Bcfe. The increase in proved reserves was primarily attributable to increased commodity pricing and drilling activity, which resulted in total upward revisions of 2,201.0 Bcfe. In addition, in September 2025, BKV Upstream Midstream acquired 100% of the equity interests of BKV Barnett II (formerly known as Bedrock Production, LLC), increasing reserves by 743.0 Bcfe. Our extensions and discoveries and improved recoveries experienced in 2025 also resulted in net increases to proved reserves of 129.6 Bcfe and 20.6 Bcfe, respectively. We produced 305.0 Bcfe during the year ended December 31, 2025.

Revisions of previous estimates primarily consisted of upward revisions to proved developed reserves and proved undeveloped reserves of 915.8 Bcfe and 679.2 Bcfe, respectively, as a result of higher average pricing during 2025 for natural gas, NGLs, and oil. Additional upward revisions were made to proved undeveloped reserves of 599.2 Bcfe due to increases in capital spend and drilling activity during 2025. Changes to the drilling schedule added 86.0 gross (81.2 net) proved locations in NEPA and the Barnett to be developed within 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 129.6 Bcfe of proved undeveloped reserves across 11.0 gross (8.9 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, 2025.

Improved recoveries added 20.6 Bcfe of proved developed reserves achieved through the continued enhancement of recovery techniques applied to producing wells during the year ended December 31, 2025.

Purchases of minerals in place consisted of 494.6 Bcfe and 248.4 Bcfe of acquired proved developed reserves and proved undeveloped reserves, respectively, from the Bedrock Acquisition, which represented 1,002.0 gross (877.6 net) locations in the Barnett.

Conversions of proved undeveloped reserves to proved developed reserves consisted of 211.8 Bcfe related to the completion of 34.0 gross (31.0 net) wells during the year ended December 31, 2025 that were converted to proved developed wells, previously classified as proved undeveloped.

***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 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 primarily consisted of 139.2 Bcfe of proved undeveloped reserves across 16.0 gross (14.4 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 consisted of 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.

Sales 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.

***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 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 our long-term plan to best develop our 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.

***Estimated Reserves at NYMEX Strip Pricing***

The following table provides our total estimated proved reserves information prepared by Ryder Scott as of December 31, 2025, using NYMEX strip prices as of market close on December 31, 2025 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, 2025. The historical 12-month pricing average in our December 31, 2025 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, 2025. 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*" in the Original Form 10-K.

| | December 31, 2025 |
|---|---|
| **Estimated proved developed reserves at NYMEX Strip Pricing:** | |
| Natural gas (MMcf) | 3,156,787 |
| Producing | 2,972,440 |
| Non-producing | 184,347 |
| Natural gas liquids (MBbls) | 183,504 |
| Producing | 163,078 |
| Non-producing | 20,426 |
| Oil (MBbls) | 1,760 |
| Producing | 1,597 |
| Non-producing | 163 |
| Total estimated proved developed reserves (MMcfe) | 4,268,371 |
| Producing | 3,960,490 |
| Non-producing | 307,881 |
| **Estimated proved undeveloped reserves at NYMEX Strip Pricing:** | |
| Natural gas (MMcf) | 1,243,920 |
| Natural gas liquids (MBbls) | 74,843 |
| Oil (MBbls) | 2,086 |
| Total estimated proved undeveloped reserves (MMcfe) (1), (2) | 1,705,494 |
| **Estimated total proved reserves at NYMEX Strip Pricing:** | |
| Natural gas (MMcf) | 4,400,707 |
| Natural gas liquids (MBbls) | 258,347 |
| Oil (MBbls) | 3,846 |
| Total estimated proved reserves (MMcfe) | 5,973,865 |
| Standardized Measure (millions) | $ 2,574 |
| PV-10 (millions) (3) | $ 3,082 |

(1) Proved undeveloped reserves December 31, 2025 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, 2025:

| | December 31, 2025 |
|---|---|
| PV-10 (millions) | $ 3,082 |
| Present value of future income taxes discounted at 10% | (508) |
| Standardized Measure | $ 2,574 |

**Preparation of Reserves Estimates and Internal Controls**

Our reserves estimates as of December 31, 2025, 2024, and 2023 included in the Original Form 10-K and this Amendment No. 1 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 the Original Form 10-K.

Prior to our annual reserves process, our internal staff of petroleum engineers, geoscience professionals, operations, land, finance and accounting, and marketing personnel work closely together to ensure the integrity, accuracy, and timeliness of our reserves data. Our reservoir engineering team then reviews such data and provides it to, and works closely with, our independent reserves engineers as part of 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 17 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 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. The internal reservoir engineering team reports directly to our President of Upstream. Management is responsible for establishing internal controls used in the preparation of our oil and gas reserves, which include verification of data input into reserves forecasting and economics evaluation software and multi-discipline management reviews performed by the corporate reserves team.

**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. Our enterprise risk management function is overseen by the Senior Director of Risk Management, who coordinates our risk assessment and monitoring processes and reports to executive leadership. The RMC is comprised of executives and senior leaders across various functions, including legal, information technology, marketing, regulatory and sustainability, safety, security, operations, finance and accounting, and land.

**Customers and Product Marketing**

*Natural Gas and NGLs*. We utilize an unaffiliated third party to market all of our natural gas production to various purchasers, which consist of creditworthy counterparties, including utilities, LNG producers, industrial consumers, major corporations, and super majors in our industry. We rely on the creditworthiness 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.

*Power*. BKV-BPP Power sells electricity and related products through two primary channels: (i) wholesale merchant energy sales, including fixed-price forward power sales and heat rate call option (HRCO) contracts into the ERCOT market, and (ii) retail electricity sales to commercial, industrial, and residential customers throughout the deregulated portions of Texas, under the brand name, BKV Energy.

**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). We will periodically enter into longer-term commitments with downstream pipelines for firm transportation service. As of December 31, 2025, 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 10 years, with an average remaining duration of 3.6 years as of December 31, 2025.

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 2026 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 (“Houston Pipe Line”), which expires in 2027. We also received two firm transport contracts with these same shippers from the Bedrock Acquisition for 23,750 MMBtu/d each, both subject to yearly volume reductions that expire in 2028. These contracts with Energy Transfer and Houston Pipe Line provide 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 December 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 December 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, 2025, our minimum aggregate required payments per year under firm gathering and transportation agreements were $70.2 million for 2026, $62.1 million for 2027, $53.9 million for 2028, $34.3 million for 2029, $5.9 million for 2030, and $33.0 million for 2031 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 both our Upstream/Midstream and Power segments.

*Upstream/Midstream.* 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 may also have detrimental effects on available supply.

*Power*. Our Power segment is subject to similar, and in some respects, more acute seasonal dynamics. Power prices in the ERCOT market are highly responsive to weather conditions, time of day, and generation mix, and can experience significant volatility on a daily and seasonal basis. Extreme weather events, including severe winter and summer temperature events that have historically affected the Texas market can cause sharp spikes in both power demand and wholesale energy prices, which may materially benefit or adversely affect our power operations depending on the availability of our generation assets and the nature of our hedging positions. Periods of mild weather, conversely, can suppress both natural gas demand and power prices, reducing revenues across our upstream and power segments.

Seasonal anomalies, such as warmer than normal winters or cooler than normal summers, can also increase competition for equipment, supplies, and personnel, which could lead to shortages and increased costs or delays in our operations. Similarly, winter months may bring about delays in operational capabilities and efficiency of execution related to new and existing supply.

**Competition**

*Upstream/Midstream.* 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 in 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. Occasionally, such materials, equipment, and labor may be in short supply. 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.

*Power*. Our power generation business competes with other generators operating in the ERCOT market, including other combined-cycle gas-fired plants, renewable energy generators, and other dispatchable resources. Competition in the ERCOT market is influenced by natural gas prices, transmission constraints, the generation mix, and regulatory developments. In the retail electricity market, BKV Energy competes with other retail electric providers (“REPs”) licensed to operate in the deregulated portions of Texas, including large incumbent utilities, national retail electricity providers, and other independent REPs. Competition in the retail market is based on pricing, customer service, product offerings, and brand recognition.

In addition, the oil and gas and power industries generally compete with other industries supplying energy and fuel to industrial, commercial, and individual consumers, including alternative and renewable energy sources. The transition toward renewable generation in the ERCOT market could increase competition for our power generation business, though we believe our highly efficient, dispatchable combined-cycle assets are well-positioned to serve the reliability needs of the grid.

**Ownership by our Directors and Officers in Other Entities**

Most of our non-independent 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. In addition, certain of 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, 2025, we had a total of 452 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, including both our upstream and power generation assets. We conduct routine maintenance and inspections at our facilities, and we have established practices and operational infrastructure to control and mitigate potential spills, discharges, or equipment failures. 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 Benefit***s. 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 in 2024 and again in late-2025 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 the disposal or other disposition of produced water;
- 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, 2025 we have recorded asset retirement obligations of $233.3 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 Act***. The Oil Pollution Act of 1990, or the OPA, contains numerous restrictions relating to the prevention of and response to oil spills into waters of the United States. The term "waters of the United States" has been interpreted broadly to include inland water bodies, including wetlands and intermittent streams. The OPA imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening waters of the United States or adjoining shorelines. For example, operators of certain oil and gas facilities must develop, implement, and maintain facility response plans, conduct annual spill training for certain employees, and provide varying degrees of financial assurance. Owners or operators of a facility, vessel, or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge is one type of "responsible party" who is liable. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs, and certain other damages arising from a spill. As such, a violation of the OPA has the potential to adversely affect our business, financial condition, results of operations and cash flows.

***Clean Water Act***. The 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*" in the Original Form 10-K.

***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, Texas, Wyoming, North Dakota, West Virginia, and Arizona, 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 Fracturin*g.** 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. In late 2025, the EPA issued final rules extending certain compliance deadlines in the Methane Rule and the NSPS rules for the oil and gas sector. It remains to be seen what impact the Trump Administration ultimately 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 the Original Form 10-K.

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, in the past 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, commonly known as the "Endangerment Finding," which underpins the EPA's regulation of greenhouse gas emissions. On February 18, 2026, the EPA published a final rule rescinding the Endangerment Finding. The rescission has been challenged in court, which could result in the rescission being stayed, overturned or limited in scope or effect. If the rescission remains in effect, the EPA may seek in the future to repeal or lessen the stringency of regulations affecting the oil and natural gas industry that are based, at least in part, on the Endangerment Finding. Further, it is possible that efforts to regulate GHGs at the national level in the United States, which could include reconsidering the Endangerment Finding, could occur in the future. The ultimate outcome and long-term effect of the rescission of the Endangerment Finding, as well as its impact on regulation of the oil and natural gas industry, remains uncertain.

The EPA 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. On September 12, 2025, the EPA issued a proposed rule that would rescind the GHG reporting rule, other than for natural gas systems subject to waste emission charges, and would delay requirements for these systems until 2034. It remains to be seen what the ultimate outcome of this proposal will be and what the ultimate impact and long-term effect the Trump Administration rollback initiatives 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 the Original Form 10-K.

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, which set an economy-wide target of net GHG emissions reduction from 2005 levels of 50-52% by 2030. However, effective on January 26, 2026, the Trump Administration again formally exited the Paris Agreement. It remains to be seen what the long-term effect of this action will be.

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 Jobs Act signed into law in November 2021 included measures aimed at decarbonization to address climate change, including funding for replacing transit vehicles, including buses, with zero- and low-emission vehicles and for the deployment of an electric vehicle charging network nationwide. This legislation, and other future laws, that promote a shift toward electric vehicles could adversely affect the demand for our products. Similarly, the Inflation Reduction Act 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, if and when they take effect, 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. The Trump Administration has delayed or rolled back most of the climate-related measures taken under the Biden administration, but it is possible that future administrations could again pursue these or other climate-related initiatives.

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. Litigation challenging the California climate disclosure laws is ongoing. Although reporting under both laws was slated to commence in 2026, on November 18, 2025, the U.S. Court of Appeals for the Ninth Circuit issued an injunction prohibiting enforcement of the climate-related financial risk disclosure law pending its consideration of a First Amendment challenge to the law. The California Air Resources Board has issued guidance on compliance with the disclosure laws and is in the process of developing regulations to implement the California climate-related disclosure requirements. Furthermore, if the SEC's climate disclosure requirements remain in place and are ultimately enforced by the SEC or if similar requirements are put in place in the future, 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***. Attention to environmental justice considerations — from activist groups and/or government regulators — may impede or otherwise have an adverse effect on our ability to develop both our fossil fuel assets and our proposed CCUS projects. For example, the Biden Administration created a White House Office of Environmental Justice in April 2023, 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. Although this office no longer exists and environmental justice considerations are not a focus of the Trump Administration, a future administration could change course and, if so, the development and application of 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*" in the Original Form 10-K.

**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 office in Fort Worth, Texas and have 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 Amendment No. 1 or our other filings with the SEC and is not a part of them.

**Information about our Executive Officers (as of March 6, 2026)**

| Name | Age | Current Title (Year Initially Elected an Executive Officer) |
|---|---|---|
| Christopher P. Kalnin | 48 | Chief Executive Officer (2020) |
| David R. Tameron | 58 | Chief Financial Officer (2025) |
| Eric S. Jacobsen | 55 | President — Upstream (2020) |
| Barry S. Turcotte | 55 | Chief Accounting Officer (2022) |
| Lindsay B. Larrick | 43 | Chief Legal and Chief Administrative Officer (2022) |
| Ethan Ngo | 44 | Chief Corporate Development Officer (2022) |
| Dilanka Seimon | 45 | Chief Commercial Officer (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.

**David R. Tameron** has served as Chief Financial Officer of the Company since April 2025. Mr. Tameron previously served as the Company's Vice President, Strategic Finance and Investor Relations from August 2022 to March 2025. Prior to joining BKV in August 2022, Mr. Tameron served in various roles at Wells Fargo & Company, including as Managing Director of Denver-based Corporate Banking, from September 2017 to August 2022, and as Managing Director, Institutional Equity Research, from July 2006 to August 2017. Mr. Tameron earned an MBA from the Fuqua School of Business at Duke University and a BA in Finance from Arizona State University.

**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.

**Dilanka Seimon** has served as Chief Commercial Officer of the Company since April 2025. Prior to joining the Company, Mr. Seimon served as Executive Vice President and Chief Commercial Officer at EnLink Midstream (now, ONEOK) from August 2023 to February 2025, and as Vice President of Alternative Energy at Energy Transfer (NYSE: ET), from January 2022 to August 2023. From March 2013 through December 2021, Mr. Seimon served at BHP Group Limited (NYSE: BHP), the world’s largest mining company by market capitalization, working his way up to Vice President of Sales and Marketing. Earlier in his career, he held various roles in business development, natural gas trading, marketing, and origination. Mr. Seimon completed the General Management Program at Harvard Business School, earned an MBA from the Fuqua School of Business at Duke University, and received a BS in Economics from Georgia College & State University.

## 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 Amendment No. 1. This Amendment No. 1 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 the Original Form 10-K. Accordingly, this Amendment No. 1 should be read in conjunction with the Original Form 10-K and subsequent filings with the SEC, including the Q1 2026 Form 10-Q, the Q2 2026 Form 10-Q, and our Current Reports on Form 8-K. These subsequent SEC filings contain important information regarding events, risks, developments, and updates affecting us and our expectations that have occurred since the filing of the Original Form 10-K.*

### Overview

We are a forward-thinking, growth-driven energy company focused on creating long-term risk-adjusted stockholder value through the development of natural gas producing assets, the ownership and operation of natural gas-fired power generation assets, and selective accretive acquisitions. Our core businesses are the production of natural gas and the generation of natural gas-fired power from our owned and operated assets, supported by a closed-loop strategy enabled by our upstream, midstream, power, and CCUS businesses.

Our operations are supported by four business lines: natural gas production, natural gas midstream, power generation, and CCUS. Our operating approach is designed around a closed-loop model that aligns these business lines to support cost efficiency, commercial optimization, and operational reliability across the value chain. Through this approach, we retain operational control over the production, transportation, and processing of natural gas and provide multiple platforms for disciplined capital deployment, while meeting growing demand for low carbon natural gas and power.

For example, in the Barnett Shale, natural gas produced from our upstream assets is gathered and transported in part through our midstream systems. In November 2023, we commenced sequestration operations at our first CCUS project, and we currently expect our second and third CCUS projects to commence sequestration activities in the first and second quarter of 2026 with additional CCUS growth opportunities beyond 2026. Further, we are pursuing a power growth strategy that aligns with both our natural gas and CCUS businesses.

As part of our ongoing operations, we expect our owned and operated upstream and natural gas midstream businesses to achieve net-zero Scope 1 and Scope 2 greenhouse gas emissions during the early 2030s and net-zero Scope 1, Scope 2, and Scope 3 emissions by the late 2030s.

We believe our business model, experienced management team, and disciplined technology-enabled operations support our ability to create long-term, risk-adjusted stockholder value.

### Recent Developments

- **BKV-BPP Power Joint Venture Transaction.** On January 30, 2026, we completed the previously announced acquisition of an additional 25% interest in the BKV-BPP Power Joint Venture for aggregate consideration consisting of $115.1 million in cash and 5,315,390 shares of our common stock. We funded the cash consideration with a combination of cash on hand and the net proceeds from the 2025 Equity Offering. Following the closing of the transaction, the BKV-BPP Power Joint Venture is owned 75% by BKV and 25% by BPPUS, and certain prior period financial information has been recast to include the historical results of the BKV-BPP Power Joint Venture for all periods during which the Company and BKV-BPP Power Joint Venture were under common control, as well as a change in our reportable segments. See *Note 19 - Reportable Segments* to our consolidated financial statements for further information.

**Operational and Financial Highlights**

Below are some highlights of our operating and financial results for the year ended December 31, 2025:

- Production of natural gas, NGLs, and oil was 305.0 Bcfe, or 835.5 MMcfe/d.
- Average realized product prices, excluding the impact of settled derivatives, was $2.81 per Mcfe.
- Power generation of 7,611 GWh from the Temple Plants and capacity factor of 59.0%.
- Upstream/Midstream production revenues were $857.6 million, and Power revenues were $248.8 million.
- Net income attributable to BKV was $179.2 million.
- Net cash provided by operating activities for the year ended December 31, 2025 was $280.4 million.
- Accrued capital expenditures for the year ended December 31, 2025 were $323.3 million.

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

Our business depends on many factors, including, but not limited to: (i) commodity prices, (ii) market supply and demand for natural gas, NGLs, and power, and (iii) upstream and power capital and operating 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, NGL, and power industries are each cyclical and seasonal, 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 operations to provide an economic hedge of our exposure to commodity price risks associated with anticipated future natural gas and NGL production and power generation. 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 Power Prices***. Natural gas, NGL, and power prices are subject to large fluctuations in response to relatively minor changes in the demand for natural gas, NGLs, and power. Natural gas and NGL 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, industry-wide supply chain disruptions, widespread shortages of labor, material, and services. Other factors impacting supply and demand include weather conditions (including severe weather events), pipeline capacity constraints, basis differentials, export capacity, supply chain quality and availability. Power prices in the ERCOT market are subject to large fluctuations in response to relatively minor changes in the weather, time of day and generation mix, along with current and expected supply and demand dynamics in the ERCOT market. The majority of the factors noted above are outside of our control.

***Power Business.*** The financial information presented in this Amendment No. 1 has been retrospectively adjusted for the BKV-BPP Power Joint Venture Transaction, which was accounted for as a transaction between entities under common control and resulted in a change in our reportable segments. Accordingly, prior period financial information has been recast to include the historical results of the BKV-BPP Power Joint Venture for all periods during which the Company and BKV-BPP Power Joint Venture were under common control and to reflect the current reportable segment presentation. However, the power business has historically operated separately from our other operations and has a different operating profile. Businesses engaged in power generation are subject to seasonal, daily, and hourly fluctuations in demand, periods of peak load, and changes in supply and demand dynamics, which can result in variability in revenues and operating costs. In addition, the power generation business is capital intensive, requiring ongoing investments in land, modular generation equipment, and turbine generators, and its growth is dependent on access to capital and the ability to obtain necessary commercial agreements. As a result, our consolidated results may not be fully comparable across periods and may not be indicative of the results that would have been achieved if the power business had been operated as part of our company during those periods or of our future performance.

***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 and Power Data***

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| **Production Data** | | | |
| Natural gas (MMcf) | 242,935 | 228,682 | 249,766 |
| NGLs (MBbls) | 10,181 | 9,858 | 10,554 |
| Oil (MBbls) | 159 | 96 | 119 |
| Total volumes (MMcfe) | 304,975 | 288,406 | 313,804 |
| Average daily total volumes (MMcfe/d) | 835.5 | 788.0 | 859.7 |
| **Power Data** | | | |
| Power generation (GWh) | 7,611 | 7,360 | 7,230 |
| Fuel consumption (MMBtu) | 54,333 | 52,213 | 51,603 |

***Impact of Acquisition and Joint Venture Transactions***. Our financial condition and results of operations for the periods presented were impacted by acquisitions and joint venture transactions completed during 2025, which changed the scale, composition, and ownership structure of our operations.

In May 2025, as part of our CCUS business strategy, we partnered with the Class B Member to form the BKV-CIP Joint Venture, and beginning in the third quarter of 2025, we consolidated the BKV-BPP Cotton Cove Joint Venture. These transactions resulted in changes to the accounting treatment of certain assets and results, including the recognition of noncontrolling interests and fair value adjustments, further affecting comparability across periods.

In September 2025, we completed the Bedrock Acquisition, with an economic effective date of July 1, 2025. The acquisition significantly expanded our asset base in the Barnett with low-decline proved developed producing reserves, resulting in higher production volumes, revenues, operating expenses, depreciation, depletion and amortization, and asset retirement obligations beginning in the third quarter of 2025. Because the acquired assets were not owned for a full period of 2025, results are not comparable to prior periods. In addition, the consideration paid, including cash, common stock, and repayment of indebtedness, affected our liquidity, leverage, and weighted average shares outstanding.

As a result of these transactions, our historical operating, financial, and reserve data may not be comparable between periods presented in this Amendment No. 1.

**Sources of Revenues**

Our core businesses are the production of natural gas and the generation of natural gas-fired power from our owned and operated assets. Currently, a significant portion of our revenues are derived from the sale of our natural gas production and the NGLs that are extracted from processing our natural gas, as well as from the sale of our power generated out of the Temple Plants and sold to a third party at either market or negotiated contract terms. A smaller portion of our revenues are generated from the sale of crude oil, midstream and surface operations, 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. In addition, we are exposed to fluctuations in wholesale electricity prices, primarily in the ERCOT market, related to our power generation and marketing activities. Power prices are influenced by several factors, including natural gas prices, weather, and market supply and demand. 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* to our consolidated financial statements included in Item 8 of Part II, *Financial Statements and Supplementary Data* below. The following is a comparison of average pricing excluding and including the effects of derivatives:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| **Average prices:** | | | |
| ***Natural gas ($/Mcf)*** | | | |
| Average NYMEX Henry Hub price | $ 3.43 | $ 2.27 | $ 2.74 |
| Average natural gas realized price (excluding derivatives) | $ 2.78 | $ 1.69 | $ 2.04 |
| Average natural gas realized price (including derivatives) (1) | $ 2.75 | $ 2.10 | $ 2.23 |
| Differential | $ (0.65) | $ (0.58) | $ (0.70) |
| ***NGLs ($/Bbl)*** | | | |
| Average NGL realized price (excluding derivatives) | $ 17.00 | $ 16.79 | $ 17.80 |
| Average NGL realized price (including derivatives) (1) | $ 16.84 | $ 17.19 | $ 17.55 |
| ***Oil ($/Bbl)*** | | | |
| Average oil realized price | $ 59.50 | $ 68.81 | $ 70.97 |
| **High and low daily spot prices** | | | |
| ***Natural gas ($/Mcf)*** | | | |
| High NYMEX Henry Hub | $ 9.86 | $ 13.20 | $ 3.78 |
| Low NYMEX Henry Hub | $ 2.65 | $ 1.21 | $ 1.74 |
| ***Oil ($/Bbl)*** | | | |
| High NYMEX WTI | $ 80.73 | $ 87.69 | $ 93.67 |
| Low NYMEX WTI | $ 55.44 | $ 66.73 | $ 66.61 |
| **Power** | | | |
| Average power price ($/MWh) (excluding derivatives) | $ 12.31 | $ 11.21 | $ 32.42 |
| Average power price ($/MWh) (including derivatives) | $ 47.47 | $ 35.10 | $ 49.86 |
| Average natural gas cost ($/Mcf) | $ 3.32 | $ 2.27 | $ 1.83 |

(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.

**Business Segment Results of Operations**

The following sections present our results of operations for our two reportable segments, Upstream/Midstream and Power. Management believes this information is useful to investors in understanding the Company's financial condition, results of operations, and trends and uncertainties. See *Note 19 - Reportable Segments* to our consolidated financial statements included in Item 8 of Part II, *Financial Statements and Supplementary Data* below.

***Upstream/Midstream Segment***

Comparison of the Year Ended December 31, 2025 and 2024:

| (in thousands, other than percentages) | Year Ended December 31, 2025 | 2024 | Change | % Change |
|---|---|---|---|---|
| Production volume | | | | |
| Total production volumes (MMcfe) | 304,975 | 288,406 | 16,569 | 6 % |
| Average daily production (MMcfe/d) | 835.5 | 788.0 | 47.6 | 6 % |
| Average realized price (excluding derivatives) | $ 2.81 | $ 1.93 | $ 0.88 | 45 % |
| Average realized price (including derivatives) | $ 2.79 | $ 2.28 | $ 0.51 | 22 % |
| | | | | |
| Revenues and other operating income | | | | |
| Natural gas revenues | $ 675,078 | $ 385,456 | $ 289,622 | 75 % |
| NGL revenues | 173,059 | 165,508 | 7,551 | 5 % |
| Oil revenues | 9,460 | 6,606 | 2,854 | 43 % |
| Midstream revenues | 10,456 | 12,560 | (2,104) | (17)% |
| Derivative gains (losses), net | 105,081 | (34,152) | 139,233 | * |
| Gain on sale of business | — | 7,080 | (7,080) | (100)% |
| Gain (loss) on sale of assets | (1,798) | 3,523 | (5,322) | * |
| Other | 11,664 | 6,631 | 5,033 | 76 % |
| Total revenues and other operating income | 983,000 | 553,212 | 429,788 | |
| Operating expenses | | | | |
| Lease operating and workover | 152,873 | 136,991 | 15,882 | 12 % |
| Taxes other than income | 50,761 | 34,961 | 15,799 | 45 % |
| Gathering and transportation | 250,849 | 222,391 | 28,458 | 13 % |
| Depreciation, depletion, amortization, and accretion | 155,713 | 215,541 | (59,828) | (28)% |
| General and administrative | 68,944 | 59,417 | 9,527 | 16 % |
| Other operating expenses | 29,034 | 12,647 | 16,387 | * |
| Total operating expenses | 708,174 | 681,948 | 26,225 | |
| Income (loss) from operations | $ 274,826 | $ (128,736) | $ 403,562 | |

* *Percentage not meaningful*

*Natural Gas Revenues*

Our natural gas revenues increased by $289.6 million, or 75%, to $675.1 million for the year ended December 31, 2025, from $385.5 million for the year ended December 31, 2024. The impact of commodity price increases, excluding the effect of derivative settlements, provided a $265.6 million increase in year-over-year revenues (calculated as the change in the year-over-year average price times current year's production volumes). The increase was also due to higher production volumes during the year ended December 31, 2025, which accounted for a $24.0 million increase 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 increased by $7.6 million, or 5%, to $173.1 million for the year ended December 31, 2025, from $165.5 million for the year ended December 31, 2024. The increase was due to higher production volumes during the year ended December 31, 2025, which accounted for a $5.5 million increase in year-over-year revenues (calculated as the change in year-over-year volumes times the prior year's average price). The increase was also due to the impact of commodity price increases, excluding the effect of derivative settlements, which accounted for a $2.1 million increase 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 increased by $2.9 million, or 43%, to $9.5 million for the year ended December 31, 2025, from $6.6 million for the year ended December 31, 2024. The increase was due to higher production volumes during the year ended December 31, 2025, which accounted for a $4.4 million increase in year-over-year revenues (calculated as the change in year-over-year volumes times the prior year's average price). The increase was offset by the impact of commodity price decreases, excluding the effect of derivative settlements, which accounted for a $1.5 million decrease in 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 $2.1 million, or 17%, to $10.5 million for the year ended December 31, 2025, from $12.6 million for the year ended December 31, 2024. This decrease was primarily due to the divestiture of Chaffee of $2.0 million as we sold our Repsol Midstream Interest in connection with this sale.

*Derivative Gains (Losses), Net*

For the year ended December 31, 2025, our Upstream/Midstream segment had net realized and unrealized gains on derivative contracts of $105.1 million, compared to net realized and unrealized losses on derivative contracts of $34.2 million for the year ended December 31, 2024. The increase in gains for the year ended December 31, 2025 was primarily attributable to our open derivative positions, which were in more of an unrealized gain position of $113.2 million, compared to an unrealized loss position of $146.7 million for the year ended December 31, 2024. The increase in unrealized gains for the year ended December 31, 2025 reflected decreases in the forward curve of natural gas prices relative to December 31, 2024, whereas the prior year period reflected increases in forward curve of natural gas prices compared to December 31, 2023. The increased gains were offset by realized losses of $8.1 million during the year ended December 31, 2025, compared to realized gains of $112.5 million during the year ended December 31, 2024, which were due to higher natural gas prices settled in the current year compared to prior year.

*Gain on Sale of Business*

For the year ended December 31, 2025, we did not sell any businesses or subsidiaries. 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 (Losses) on Sales of Assets, Net*

For the year ended December 31, 2025, we recognized a loss of $1.8 million on sales of assets compared to a gain of $3.5 million on sales of assets during the year ended December 31, 2024. During the year ended December 31, 2025, we wrote-down our Bridgeport office building by $2.4 million to its sale price of $5.5 million. This was offset by other property, plant, and equipment sold for $1.3 million in proceeds, which resulted in a gain on sale of these assets of $0.6 million. 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.

*Other Revenues*

Other revenues, which primarily include the sale of third party gas, were $11.7 million for the year ended December 31, 2025, compared to $6.6 million for the year ended December 31, 2024. The year-over-year increase was primarily due to an increase in gas prices and contracted rates.

*Lease Operating and Workover*

The following table summarizes our components of lease operating expenses for the periods presented:

| | Year Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2025 | | 2024 | | | |
| **(in thousands, other than percentages and average costs)** | **Amount** | **Per Mcfe** | **Amount** | **Per Mcfe** | **Change** | **% Change** |
| Lease operating expenses | $ 145,631 | $ 0.48 | $ 132,317 | $ 0.46 | $ 13,314 | 10 % |
| Workover expenses | 7,242 | 0.02 | 4,674 | 0.01 | 2,568 | 55 % |
| Total lease operating and workover expense | $ 152,873 | $ 0.50 | $ 136,991 | $ 0.47 | $ 15,882 | 12 % |

Lease operating and workover expenses were $152.9 million, or $0.50 per Mcfe, for the year ended December 31, 2025, an increase of $15.9 million, or 12%, from $137.0 million, or $0.47 per Mcfe, for the year ended December 31, 2024. The increase was primarily attributable to $9.2 million of lease operating and workover expenses associated with BKV Barnett II, which was acquired in connection with the Bedrock Acquisition in September 2025. In addition, lease operating and workover expenses increased due to higher project activity related to our Pad of the Future program of $5.0 million and higher vehicle expenses of $1.0 million during 2025. 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. These increases were partially offset by lower compression and water expenses of $1.5 million and favorable timing of inspection fees of $0.6 million during the year ended December 31, 2025, compared to the year ended December 31, 2024.

*Taxes Other Than Income*

Taxes other than income were $50.8 million, or $0.17 per Mcfe, for the year ended December 31, 2025, which was an increase of $15.8 million, or 45%, from $35.0 million, or $0.12 per Mcfe, for the year ended December 31, 2024. The increase was due to increases in production taxes of $16.0 million in the Barnett, which includes increases of $1.6 million in production taxes from the BKV Barnett II from the Bedrock Acquisition, and increases of $0.6 million in severance taxes related to our NEPA natural gas properties. BKV Barnett II also incurred $0.5 million of ad valorem taxes during the year ended December 31, 2025. This was offset by decreases in ad valorem and property taxes associated with our operations in the Barnett of $1.4 million. Certain ad valorem and production taxes are not applicable to our NEPA properties.

*Gathering and Transportation*

Gathering and transportation expenses were $250.8 million, or $0.82 per Mcfe, for the year ended December 31, 2025, which was an increase of $28.5 million, or 13%, from $222.4 million, or $0.77 per Mcfe, for the year ended December 31, 2024. This increase was primarily attributable to higher natural gas and NGL production, which increased gathering and transportation expenses by $21.2 million, including an increase of $6.9 million related to production from BKV Barnett II. In addition, higher gathering and transportation rates for natural gas and NGLs of $8.5 million contributed to the increase in gathering and transportation expenses. This was offset by a $1.3 million decrease in gathering costs associated with our midstream business.

*Depreciation, Depletion, Amortization, and Accretion*

Depreciation, depletion, amortization, and accretion was $155.7 million, or $0.52 per Mcfe, for the year ended December 31, 2025, which was a decrease of $59.8 million, or 28%, from $215.5 million, or $0.75 per Mcfe, for the year ended December 31, 2024. The decrease was primarily due to a depletion rate adjustment in 2025, which was driven by higher reserves.

*General and Administrative*

General and administrative expenses were $68.9 million, or $0.23 per Mcfe, for the year ended December 31, 2025, which was an increase of $9.5 million, from $59.4 million, or $0.21 per Mcfe, for the year ended December 31, 2024. The increase was primarily attributable to Company-wide growth initiatives, including higher headcount and employee expenses, and an increase in consulting and information technology expenses associated with the Bedrock Acquisition. The increase was partially offset by a lower allocation of corporate general and administrative costs to the Upstream/Midstream segment.

*Other Operating Expenses*

Other operating expenses were $29.0 million, or $0.10 per Mcfe, for the year ended December 31, 2025, which was an increase of $16.4 million, from $12.6 million, or $0.04 per Mcfe, for the year ended December 31, 2024. The increase in other operating expenses during the year ended December 31, 2025, compared to the same period in 2024, was driven by acquisition and transaction-related costs, including $10.8 million of integration costs associated with the Bedrock Acquisition and $6.0 million increase in gas purchases resulting from higher volumes and natural gas prices.

***Power Segment***

Comparison of the Year Ended December 31, 2025 and 2024:

| (in thousands, other than percentages) | Year Ended December 31, 2025 | 2024 | Change | % Change |
|---|---|---|---|---|
| Temple I capacity factor | 59.2 % | 58.1 % | 1.1 % | 2 % |
| Temple II capacity factor | 58.7 % | 55.1 % | 3.6 % | 7 % |
| Total power generation (GWh) | 7,611 | 7,360 | 250 | 3 % |
| Fuel consumption (MMBtu) | 54,333 | 52,213 | 2,120 | 4 % |
| Average generation price (excluding derivatives) | $ 12.31 | $ 11.21 | $ 1.10 | 10 % |
| Average generation price (including derivatives) | $ 47.47 | $ 35.10 | $ 12.37 | 35 % |
| Average natural gas cost | $ 3.32 | $ 2.27 | $ 1.05 | 46 % |
| Average spark spread | $ 23.77 | $ 18.98 | $ 4.79 | 25 % |
| | | | | |
| Revenues and other operating income | | | | |
| Power revenues | $ 248,752 | $ 218,268 | $ 30,484 | 14 % |
| Derivative gains, net | 274,788 | 241,612 | 33,176 | 14 % |
| Total revenues and other operating income | 523,540 | 459,880 | 63,660 | |
| Operating expenses | | | | |
| Fuel commodity costs | 180,364 | 118,662 | 61,702 | 52 % |
| Purchased power | 113,968 | 108,327 | 5,641 | 5 % |
| Taxes other than income | 15,645 | 12,843 | 2,802 | 22 % |
| Depreciation, depletion, amortization, and accretion | 38,273 | 37,967 | 307 | 1 % |
| Power operating and maintenance | 78,435 | 81,071 | (2,636) | (3)% |
| General and administrative | 19,999 | 14,524 | 5,475 | 38 % |
| Other operating expenses | 8,296 | 1,809 | 6,487 | * |
| Total operating expenses | 454,980 | 375,203 | 79,778 | |
| Income (loss) from operations | $ 68,560 | $ 84,677 | $ (16,117) | |

* *Percentage not meaningful*

*Power Revenues*

Power revenues include merchant energy sales and revenue from our retail business. During the year ended December 31, 2025, our Power revenues were $248.8 million, which was an increase of $30.5 million, or 14%, from $218.3 million during the year ended December 31, 2024. The increase was primarily due to an increase in energy retail sales of $19.0 million due to the continued growth of BKV Energy's retail customer portfolio and the increase in merchant energy sales of $11.2 million, which was attributable to higher power prices, increased power generation, and improved capacity factors at the Temple Plants.

*Derivative Gains, Net*

For the year ended December 31, 2025, our Power segment had net realized and unrealized gains on derivative contracts of $274.8 million, compared to net realized and unrealized gains of $241.6 million for the year ended December 31, 2024. The increase of $33.2 million was primarily attributable to a $118.1 million increase in net realized gains on our power derivatives driven by lower realized ERCOT market prices relative to contracted prices. The increase was partially offset by a $58.6 million decline in unrealized gains on our open derivative positions, which decreased to $7.2 million as of December 31, 2025, from $65.7 million as of December 31, 2024. This reduction in unrealized gains was primarily attributable to increases in forward power prices relative to hedged prices and changes in the value of optionality. In addition, realized gains on our HRCOs decreased by $26.4 million primarily due to lower premium income resulting from a reduction in contracted HRCO capacity of 400 MW during 2024 compared to 200 MW during 2025. Premiums received under HRCO agreements are recognized within derivative gains, net as realized settlements.

*Fuel Commodity Costs*

Fuel commodity costs were $180.4 million for the year ended December 31, 2025, which was an increase of $61.7 million, or 52%, from $118.7 million for the year ended December 31, 2024. The increase was due to higher natural gas prices and increased fuel consumption compared to the year ended December 31, 2024.

*Purchased Power*

Purchased power costs for the retail business were $114.0 million for the year ended December 31, 2025, which was an increase of $5.6 million, or 5%, from $108.3 million for the year ended December 31, 2024. The increase was primarily driven by higher retail power purchases resulting from the continued growth of BKV Energy's retail customer portfolio.

*Taxes Other Than Income*

Taxes other than income were $15.6 million for the year ended December 31, 2025, which was an increase of $2.8 million, or 22%, from $12.8 million for the year ended December 31, 2024. The increase was driven by BKV-BPP Power's property tax reassessment.

*Depreciation, Depletion, Amortization, and Accretion*

Depreciation, depletion, amortization, and accretion was $38.3 million for the year ended December 31, 2025, which was an increase of approximately $0.3 million, or 1%, from $38.0 million for the year ended December 31, 2024, which was relatively consistent year-over-year.

*Power Operating and Maintenance*

Power operating and maintenance expenses are costs incurred to run the Temple Plants and remained relatively consistent year-over-year. These expenses were $78.4 million for the year ended December 31, 2025, which was a decrease of approximately $2.6 million, or 3%, from $81.1 million for the year ended December 31, 2024.

*General and Administrative*

General and administrative expenses were $20.0 million for the year ended December 31, 2025, which was an increase of approximately $5.5 million, from $14.5 million for the year ended December 31, 2024. The increase is primarily due to the legal and consulting fees related to the BKV-BPP Power Joint Venture Transaction, which resulted in increased corporate allocations to the Power segment, and higher credit loss expense of $1.5 million due to significant write-offs related to 2024 and 2025 customer balances. This was slightly offset by a $1.3 million decrease in the administrative service fee with BKV, attributable to lower contracted rates.

*Other Operating Expenses*

Other operating expenses were $8.3 million for the year ended December 31, 2025, which was an increase of $6.5 million, from $1.8 million for the year ended December 31, 2024. This increase was due to $6.5 million of transaction fees related to the BKV-BPP Power Joint Venture Transaction.

**Other Income Statement Line Items**

*Marketing Revenues*

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. Our marketing revenues increased by $1.6 million to $12.3 million for the year ended December 31, 2025, from $10.7 million for the year ended December 31, 2024. The increase in marketing revenues during the year ended December 31, 2025 was primarily due to a higher pricing environment compared to the year ended December 31, 2024.

*Section 45Q Tax Credits*

Our Section 45Q tax credits decreased by approximately $2.3 million, or 16%, to $11.8 million during the year ended December 31, 2025, from $14.0 million during the year ended December 31, 2024. Our Section 45Q tax credits related to $CO_2$ waste sequestration activities under our Barnett Zero Project. The decrease year-over-year was due to less $CO_2$ waste sequestered in 2025, reflecting routine fluctuations in activity levels that occur as part of our normal operations.

*General and Administrative*

Corporate and Other general and administrative expenses were $42.6 million for the year ended December 31, 2025, which was an increase of approximately $6.5 million, or 18%, from $36.1 million for the year ended December 31, 2024. The increase was primarily attributable to a lower amount of corporate general and administrative costs allocated to the Company's reportable segments, which resulted in Corporate and Other retaining an additional $16.3 million of expense. This increase was largely offset by lower consulting, legal, information technology, audit, and travel expenses.

*Other Operating Expenses*

Other operating expenses were $19.3 million for the year ended December 31, 2025, which was an increase of $12.6 million, from $6.7 million for the year ended December 31, 2024. The increase in other operating expenses during the year ended December 31, 2025, compared to the same period in 2024, was driven by a $5.6 million write-off related to an enterprise resource planning system, acquisition and transaction-related costs, including $5.5 million of costs and fees related to CCUS transactions, and $1.0 million of grant expense.

*Other Income (Expense)*

*Gains on contingent consideration liabilities*. For the year ended December 31, 2024, 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, consisting of a gain of $7.5 million and a gain of $2.2 million from the Devon Barnett Acquisition and the Exxon Barnett Acquisition, respectively. The contingent consideration provisions under these purchase agreements expired in 2024.

*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 Agreement and Revolving Credit Agreement that took place in June 2024.

*Interest expense.* Interest expense was $72.3 million for the year ended December 31, 2025, which was a decrease of $23.9 million, from $96.2 million for the year ended December 31, 2024. The decrease in interest expense during the year ended December 31, 2025 was primarily due to lower interest rates and a lower outstanding balance on our RBL Credit Agreement, which we entered into on June 11, 2024 and on our Temple Term Loan Facility. We also subsequently paid down 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, related party was $19.7 million for the year ended December 31, 2025, which was a decrease of $7.8 million, from $27.5 million for the year ended December 31, 2024. The decrease was primarily due to a lower outstanding balance on the Temple I Loan Agreements year-over-year.

*Interest income*. Interest income was $4.1 million for the year ended December 31, 2025, which was a decrease of $3.2 million, from $7.3 million for the year ended December 31, 2024. The decrease was due to the cessation of interest earned on restricted cash following the repayment of the Term Loan Credit Agreement in June 2024, which had previously funded the debt service reserve account.

*Income tax benefit (expense)*. For the year ended December 31, 2025, we had an income tax expense of $36.9 million, which was a change of $79.3 million, from a $42.4 million income tax benefit for the year ended December 31, 2024. The year-over-year change was primarily due to a pre-tax income for the year ended December 31, 2025, compared to a pre-tax loss for the year ended December 31, 2024.

**Business Segment Results of Operations**

The following sections present our results of operations for our two reportable segments, Upstream/Midstream and Power. Management believes this information is useful to investors in understanding the Company's financial condition, results of operations, and trends and uncertainties. See *Note 19 - Reportable Segments* to our consolidated financial statements included in Item 8 of Part II, *Financial Statements and Supplementary Data* below.

***Upstream/Midstream Segment***

Comparison of the Year Ended December 31, 2024 and 2023:

| (in thousands, other than percentages) | Year Ended December 31, 2024 | Year Ended December 31, 2023 | Change | % Change |
|---|---|---|---|---|
| Production volume | | | | |
| Total production volumes (MMcfe) | 288,406 | 313,804 | (25,398) | (8)% |
| Average daily production (MMcfe/d) | 788.0 | 859.7 | (71.7) | (8)% |
| Average realized price (excluding derivatives) | $ 1.93 | $ 2.25 | $ (0.32) | (14)% |
| Average realized price (including derivatives) | $ 2.28 | $ 2.39 | $ (0.11) | (5)% |
| | | | | |
| Revenues and other operating income | | | | |
| 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) | * |
| Gain on sale of business | 7,080 | — | 7,080 | 100 % |
| Gain on sale of assets, net | 3,523 | 2,162 | 1,361 | 63 % |
| Other | 6,631 | 3,957 | 2,674 | 68 % |
| Total revenues and other operating income | 553,212 | 967,181 | (413,969) | |
| Operating expenses | | | | |
| Lease operating and workover | 136,991 | 150,647 | (13,656) | (9)% |
| Taxes other than income | 34,961 | 72,290 | (37,329) | (52)% |
| Gathering and transportation | 222,391 | 248,990 | (26,599) | (11)% |
| Depreciation, depletion, amortization, and accretion | 215,541 | 223,165 | (7,624) | (3)% |
| General and administrative | 59,417 | 65,852 | (6,435) | (10)% |
| Other operating expenses | 12,647 | 12,353 | 294 | 2 % |
| Total operating expenses | 681,948 | 773,297 | (91,349) | |
| Income (loss) from operations | $ (128,736) | $ 193,884 | $ (322,620) | |
| | | | | |
| Per unit costs | | | | |
| 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 | $ 0.77 | $ 0.79 | $ (0.02) | (3)% |
| Depreciation, depletion, amortization, and accretion | $ 0.75 | $ 0.71 | $ 0.04 | 6 % |
| General and administrative | $ 0.21 | $ 0.21 | $ — | — % |
| Other operating expenses | $ 0.04 | $ 0.04 | $ — | — % |
| Total | $ 2.36 | $ 2.46 | $ (0.10) | |

* *Percentage not meaningful*

*Natural Gas Revenues*

Our natural gas revenues decreased by $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 decrease was due to commodity price decreases, excluding the effect of derivative settlements, which 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 $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) and 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 $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), and due to the impact of commodity price decreases, excluding the effect of derivative settlements, which accounted for a $0.2 million decrease in 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 $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 the 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, our Upstream/Midstream segment had net realized and unrealized losses on derivative contracts of $34.2 million, compared to net realized and unrealized gains of $238.7 million for the year ended December 31, 2023. The losses for the year ended December 31, 2024, were primarily attributable to our open derivative positions, which were in more of an unrealized loss position of $146.7 million, compared to an unrealized gain position of $148.6 million for the year ended December 31, 2023. The increase in unrealized losses for the year ended December 31, 2024 reflected increases in the forward curve of natural gas prices relative to December 31, 2023, whereas the prior year period reflected decreases in the forward curve of natural gas prices relative to December 31, 2022. The losses were slightly offset by higher realized gains compared to the year ended December 31, 2023, of $22.3 million, due to slightly lower natural gas prices settled during the year ended December 31, 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 (Losses) on Sales of Assets, Net*

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.

*Other Revenues*

Other revenues, which primarily include the sale of third party gas, were $6.6 million for the year ended December 31, 2024, compared to $4.0 million for the year ended December 31, 2023. The year-over-year increase was primarily due to an increase in third party gas sales of $2.7 million.

*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 $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-operated 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 $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 $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 $215.5 million, or $0.75 per Mcfe, for the year ended December 31, 2024, which was a decrease of $7.6 million, or 3%, from $223.2 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 $59.4 million, or $0.21 per Mcfe, for the year ended December 31, 2024, which was a decrease of approximately $6.4 million, from $65.9 million, or $0.21 per Mcfe, for the year ended December 31, 2023. The decrease was primarily attributable to a lower allocation of corporate general and administrative costs. Excluding the impact of these allocations, general and administrative expenses increased primarily as a result of higher consulting, legal, information technology, payroll, and travel costs associated with the Company's growth initiatives and public company readiness initiatives.

*Other Operating Expenses*

Other operating expenses remained relatively consistent year-over-year. These expenses were $12.6 million, or $0.04 per Mcfe, for the year ended December 31, 2024, which was an increase of $0.3 million, or 2%, from $12.4 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 was primarily driven by the following factors: $3.4 million in higher emissions monitoring costs, $1.0 million in costs from the newly enacted EPA fees under the Inflation Reduction Act, $0.7 million in well clean-up costs, and $0.2 million of expenses related to our IPO equity raise. These increases were offset by $2.5 million of rig termination fees, $1.2 million restocking fees, and $0.7 million in inventory write-offs that took place during the year ended December 31, 2023, and $0.7 million of lower midstream operating expenses during the year ended December 31, 2024.

***Power Segment***

Comparison of the Year Ended December 31, 2024 and 2023:

| (in thousands, other than percentages) | Year Ended December 31, 2024 | Year Ended December 31, 2023 | Change | % Change |
|---|---|---|---|---|
| Temple I capacity factor | 58.1 % | 57.4 % | 0.7 % | 1 % |
| Temple II capacity factor | 55.1 % | 54.4 % | 0.7 % | 1 % |
| Total power generation (GWh) | 7,360 | 7,230 | 130 | 2 % |
| Fuel consumption (MMBtu) | 52,213 | 51,603 | 610 | 1 % |
| Average generation price (excluding derivatives) | $ 11.21 | $ 32.42 | $ (21.21) | (65)% |
| Average generation price (including derivatives) | $ 35.10 | $ 49.86 | $ (14.76) | (30)% |
| Average natural gas cost | $ 2.27 | $ 1.83 | $ 0.45 | 24 % |
| Average spark spread | $ 18.98 | $ 36.83 | $ (17.85) | (48)% |
| | | | | |
| Revenues and other operating income | | | | |
| Power revenues | $ 218,268 | $ 274,623 | $ (56,355) | (21)% |
| Derivative gains, net | 241,612 | 51,981 | 189,631 | * |
| Total revenues and other operating income | 459,880 | 326,604 | 133,276 | |
| Operating expenses | | | | |
| Fuel commodity costs | 118,662 | 94,213 | 24,448 | 26 % |
| Purchased power | 108,327 | 27,769 | 80,558 | * |
| Taxes other than income | 12,843 | 8,827 | 4,016 | 45 % |
| Depreciation, depletion, amortization, and accretion | 37,967 | 31,752 | 6,214 | 20 % |
| Power operating and maintenance | 81,071 | 56,365 | 24,706 | 44 % |
| General and administrative | 14,524 | 27,917 | (13,393) | (48)% |
| Other operating expenses | 1,809 | 1,671 | 138 | 8 % |
| Total operating expenses | 375,203 | 248,514 | 126,687 | |
| Income (loss) from operations | $ 84,677 | $ 78,090 | $ 6,587 | |

* *Percentage not meaningful*

*Power Revenues*

Power revenues include merchant energy sales and revenue from our retail business. During the year ended December 31, 2024, our Power revenues were $218.3 million, which was a decrease of $56.4 million, or 21%, from $274.6 million during the year ended December 31, 2023. The decrease was primarily due to a decrease in merchant energy sales of $151.9 million, which was attributable to lower power prices. This was offset by an increase in energy retail sales of $95.4 million due to higher retail sales resulting from the continued growth of BKV Energy's retail customer portfolio following the commencement of its retail operations in February 2023.

*Derivative gains, net*

For the year ended December 31, 2024, our Power segment had net realized and unrealized gains on derivative contracts of $241.6 million, compared to net realized and unrealized gains of $52.0 million for the year ended December 31, 2023. The increase in gains of $189.6 million was primarily attributable to our open derivative positions, which were in an unrealized gain position of $65.7 million as of year ended December 31, 2024, compared to an unrealized loss position of $74.2 million for the year ended December 31, 2023. This change is largely due to decreases in power prices relative to hedged prices and the value of optionality. We also had an increase in realized gains of $33.4 million on our HRCOs during the year ended December 31, 2024, which was primarily due to higher contracted capacity in 2024, compared to 2023, resulting in higher premium income. Premiums received under HRCO agreements are recognized within derivative gains, net as realized settlements. These increases were also due to a $16.3 million increase in net realized gains on our power derivatives driven by lower realized ERCOT market prices relative to contracted prices.

*Fuel Commodity Costs*

Fuel commodity costs were $118.7 million for the year ended December 31, 2024, which was an increase of $24.4 million, or 26%, from $94.2 million for the year ended December 31, 2023. The increase was due to higher natural gas prices and slightly higher fuel consumption compared to the year ended December 31, 2023.

*Purchased Power*

Purchased power costs for the retail business were $108.3 million for the year ended December 31, 2024, which was an increase of $80.6 million, from $27.8 million for the year ended December 31, 2023. The increase was primarily due to higher retail power purchases resulting from the continued growth of BKV Energy's retail customer portfolio following the commencement of its retail operations in February 2023.

*Taxes Other Than Income*

Taxes other than income were $12.8 million for the year ended December 31, 2024, which was an increase of approximately $4.0 million, or 45%, from $8.8 million for the year ended December 31, 2023. The increase was driven by BKV-BPP Power's property tax reassessment.

*Depreciation, Depletion, Amortization, and Accretion*

Depreciation, depletion, amortization, and accretion was $38.0 million for the year ended December 31, 2024, which was an increase of approximately $6.2 million, or 20%, from $31.8 million for the year ended December 31, 2023. The increase was primarily attributable to the Temple II plant placed into service for a full year in 2024 following its acquisition by BKV-BPP Power in 2023.

*Power Operating and Maintenance*

Power operating and maintenance expenses are costs incurred to run the Temple Plants. These expenses were $81.1 million for the year ended December 31, 2024, which was an increase of approximately $24.7 million, or 44%, from $56.4 million for the year ended December 31, 2023. The increase was primarily due to a full year of operations and maintenance of the Temple II plant in 2024.

*General and Administrative*

General and administrative expenses were $14.5 million for the year ended December 31, 2024, which was a decrease of approximately $13.4 million, from $27.9 million for the year ended December 31, 2023. The decrease was primarily attributable to lower consulting, power marketing, and legal expenses following the start-up of BKV Retail in 2023, which resulted in higher start-up costs during the year ended December 31, 2023. The decreases were partially offset by higher credit loss expense and increased allocations of corporate general and administrative costs.

*Other Operating Expenses*

Other operating expenses remained consistent year-over-year at $1.8 million for the year ended December 31, 2024, which was an increase of approximately $0.1 million, from $1.7 million for the year ended December 31, 2023.

**Other Income Statement Line Items**

*Marketing Revenues*

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. 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. 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.

*Section 45Q Tax Credits*

Our Section 45Q tax credits increased by approximately $13.3 million, to $14.0 million during the year ended December 31, 2024, from $0.7 million during the year ended December 31, 2023. This increase was due to higher volumes of $CO_2$ waste sequestered during the year ended December 31, 2024, which started in the fourth quarter of 2023. Our Section 45Q tax credits relate to $CO_2$ waste sequestration activities associated with our Barnett Zero Project.

*General and Administrative*

Corporate and Other general and administrative expenses were $36.1 million for the year ended December 31, 2024, which was a decrease of approximately $3.7 million, from $39.8 million for the year ended December 31, 2023. The decrease was primarily attributable to lower consulting, power marketing, and legal expenses following the Company's transition to a public company. These decreases were largely offset by a lower allocation of corporate general and administrative costs to the Company's reportable segments.

*Other Operating Expenses*

Other operating expenses were $6.7 million for the year ended December 31, 2024, which was an increase of $6.5 million, from $0.3 million 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 driven by $5.3 million in CCUS operating expenses associated with operating our first CCUS Class II injection well, Barnett Zero, which came online in November 2023. The increase was also due to increased legal expenses and contingency reserves, each in the amount of $0.6 million.

*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 in 2024, compared to $38.4 million in 2023, which was a decrease of $28.7 million. The decrease was primarily attributable to lower gains on contingent consideration liabilities with the Devon Barnett Acquisition and the Exxon Barnett Acquisition. Gains related to the Devon Barnett Acquisition were $7.5 million in 2024 compared to $25.0 million in 2023, and gains related to the Exxon Barnett Acquisition were $2.2 million in 2024 compared to $13.4 million in 2023. The higher gains in 2023 were 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 that year compared to slight decreases in 2024.

*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 Agreement and Revolving Credit Agreement that took place in June 2024.

*Interest expense.* Interest expense was $96.2 million for the year ended December 31, 2024, which was an increase of $0.7 million, from $95.5 million for the year ended December 31, 2023. The increase was primarily attributable to an additional $25.1 million of interest expense related to the Temple Credit Facilities, which were entered into on July 10, 2023. This increase was substantially offset by a $24.4 million reduction in interest expense resulting from lower borrowing rates under the RBL Credit Agreement, entered into on June 11, 2024, and the paydown of outstanding balances under the SCB Credit Facility, the Revolving Credit Agreement, and the Term Loan Credit Agreement, each of which incurred higher interest rates.

*Interest expense, related party.* Interest expense, related party was $27.5 million for the year ended December 31, 2024, which was a decrease of $4.6 million, from $32.1 million for the year ended December 31, 2023. The decrease was primarily due to a lower outstanding balance on the Temple I Loan Agreements year-over-year.

*Interest income*. Interest income was $7.3 million for the year ended December 31, 2024, which was an increase of $2.6 million, from $4.7 million for the year ended December 31, 2023. The increase was due to a higher cash balance during the year ended December 31, 2024, compared to the year ended December 31, 2023.

*Income tax benefit (expense)*. For the year ended December 31, 2024, we had an income tax benefit of $42.4 million, which was a change of $72.6 million, from a $30.1 million income tax expense 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.

**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 year ended December 31, 2025 were to fund the Bedrock Acquisition and the development of our natural gas properties. 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.

During the years ended December 31, 2025, 2024, and 2023, cash paid for capital expenditures was $305.1 million, $105.4 million, and $201.5 million, respectively. Our current estimated budget for total accrued capital expenditures in 2026 is approximately $570 million to $740 million on a Company-wide basis. To help fund these capital expenditures, we expect to receive approximately $85 million to $105 million of capital contributions from our joint venture partners in our CCUS and power businesses. Expected contributions from our joint venture partners would bring our 2026 net capital expenditure range to $485 million to $635 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. In addition, the development of our power generation business is capital intensive, requiring ongoing investments in land, modular equipment, and turbine generators. 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.

On January 14, 2026, we entered into a manufacturing reservation agreement related to a planned power generation project. Under the agreement, we are committed to pay up to an aggregate of $80.0 million in reservation fees, scheduled in phases during 2026, to secure future manufacturing capacity through 2028 for turbines with up to approximately 1,230 megawatts in total generation capacity. Amounts paid are generally non-refundable and will be credited against the purchase price if a definitive supply agreement is executed.

***Capital Resources***

Historically, our primary sources of capital and liquidity have consisted of internally generated cash flows from operations, together with loans, capital contributions from our majority stockholder, BNAC, and issuances of equity or debt. We also enter into financial instruments to reduce the impact of commodity and power price volatility and provide a level of certainty and stability around cash flows. We currently believe that our cash flows from operations, cash on hand, borrowings under our RBL Credit Agreement, proceeds from the issuance of the 2025 Equity Offering, and our commodity and power hedges in place will provide sufficient liquidity to fund our operations and our capital expenditures for the remainder of 2026, excluding our CCUS business. If capital expenditures were to exceed such capital sources during the remainder of 2026, we expect to fund such excess capital expenditures through the sale of oil and natural gas producing assets, leasehold interests or mineral interests, and potential issuances of equity or debt, none of which may be available on satisfactory terms, or at all. We expect to fund the majority of our CCUS business from a variety of external sources, including contributions from our joint ventures with the Class B Member and BPPUS, project-based equity partnerships, debt financing, and federal grants, with the remaining capital needs being funded with cash flows from operations.

The following table summarizes our cash flows for the years ended December 31, 2025, 2024, and 2023 (in thousands):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| Net cash provided by operating activities | $ 280,374 | $ 115,410 | $ 260,268 |
| Net cash provided by (used in) investing activities | (576,357) | 34,266 | (663,107) |
| Net cash provided by (used in) financing activities | 463,258 | (314,805) | 498,488 |
| Net increase (decrease) in cash, cash equivalents, and restricted cash | $ 167,275 | $ (165,129) | $ 95,649 |

***Cash flows provided by operating activities.*** Net cash provided by operating activities was $280.4 million for the year ended December 31, 2025, compared to $115.4 million for the year ended December 31, 2024. The increase of $165.0 million was due to a $129.0 million increase in income from operations (excluding non-cash items), resulting from higher natural gas volumes and prices compared to 2024, a $54.1 million decrease in cash paid for interest, a favorable $16.5 million change in working capital, and a decrease in transaction costs of $3.5 million. These increases were offset by $23.5 million of cash received in January 2024 for the sale of call options and $16.2 million of cash paid in February 2025 for the purchase of put options.

Net cash provided by operating activities was $115.4 million for the year ended December 31, 2024, compared to $260.3 million for the year ended December 31, 2023. The decrease of $144.9 million was due to a $173.2 million decrease in income (loss) from operations (excluding non-cash items), resulting from lower natural gas prices compared to 2023, an unfavorable $26.8 million change in working capital, a $13.8 million increase in cash paid for interest, 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.

Operating cash flow fluctuations are substantially driven by realized commodity prices, production volumes, power prices, power generated, and operating expenses. Prices for natural gas, NGLs, and power 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 used in investing activities was $576.4 million for the year ended December 31, 2025, compared to net cash provided by investing activities of $34.3 million for the year ended December 31, 2024. The $610.6 million increase in net cash outflows was driven by $272.1 million of cash paid for the Bedrock Acquisition and higher capital expenditures, including a $170.2 million increase in Upstream/Midstream capital expenditures, a $24.5 million increase in CCUS capital expenditures, and a $4.6 million increase in Corporate and Other capital expenditures. In addition, investing cash flows for the year ended December 31, 2024 benefited from $132.6 million of proceeds from the sale of Chaffee and certain non-operated upstream assets held by Chelsea, which did not occur in 2025.

Net cash provided by investing activities was $34.3 million for the year ended December 31, 2024, compared to net cash used in investing activities of $663.1 million for the year ended December 31, 2023. The $697.4 million increase in net cash inflows was primarily driven by lower acquisition-related cash outflows, as 2023 included the $480.3 million acquisition of Temple II, a combined-cycle gas and steam turbine power plant located in Temple, Texas. During the year ended December 31, 2024, investing cash flows also benefited from $132.6 million of total proceeds from the sale of Chaffee and certain non-operated upstream assets held by Chelsea and lower capital expenditures, including a $48.7 million decrease in Upstream Midstream segment capital expenditures, a $37.8 million decrease in CCUS-related expenditures, and a $9.4 million decrease in the Power segment capital expenditures. These favorable impacts were partially offset by $8.3 million of insurance proceeds received during the year ended December 31, 2023.

The following table presents our capital expenditures (excluding leasehold costs and acquisitions) on an accrual basis for the years ended December 31, 2025, 2024, and 2023 and reconciles to cash flows used for capital expenditures in the consolidated statements of cash flows.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| Total use of cash and cash equivalents for capital expenditures | $ (305,119) | $ (105,361) | $ (201,513) |
| Decrease (increase) in accrued capital expenditures | (18,204) | (16,850) | 23,178 |
| Capital expenditures (accrued) | $ (323,323) | $ (122,211) | $ (178,335) |

***Cash flows provided by (used in) financing activities.*** Net cash provided by financing activities was $463.3 million for the year ended December 31, 2025, which consisted of $500.0 million of proceeds from the issuance of the 2030 Senior Notes and $170.6 million of net proceeds from the 2025 Equity Offering (after deducting underwriting discounts and commissions). Financing inflows also included $19.8 million of cash contributions from noncontrolling interest. These inflows were offset by $208.5 million of net debt repayments and $15.9 million of payments on debt issuance costs.

Net cash used in financing activities was $314.8 million for the year ended December 31, 2024, which consisted of $503.0 million of net debt repayments, $53.2 million of payments for taxes related to net share settlement of restricted stock units, $18.3 million for payments of debt issuance costs and debt extinguishment costs, and $6.0 million of other financing costs. These outflows were partially offset by $265.7 million of net proceeds from the issuance of common stock from our IPO (after deducting underwriting discounts and commissions).

Net cash provided by financing activities was $498.5 million for the year ended December 31, 2023, which consisted of $560.0 million of proceeds from the Temple Credit Facilities and $150.0 million of capital contributions from BNAC in exchange for 7,500,000 shares of our common stock. The cash inflows were partially offset by $184.4 million of net debt repayments, $11.1 million of other financing costs $10.0 million of dividends paid to BPPUS, and $3.1 million payment on debt issuance costs.

***Working Capital***

As of December 31, 2025, we had cash and cash equivalents of $248.4 million and restricted cash of $15.8 million, compared to $81.2 million of cash and cash equivalents and restricted cash of $15.8 million as of December 31, 2024. Our net working capital deficit was $53.2 million as of December 31, 2025, compared to a net working capital deficit of $1.7 million as of December 31, 2024.

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, power prices, power generation, and differentials to NYMEX pricing for our natural gas and oil production will be the largest variables impacting our working capital.

***2030 Senior Notes***

On September 26, 2025, BKV Upstream Midstream issued in a private placement $500.0 million of 7.50% senior unsecured notes due October 15, 2030 (the “2030 Senior Notes”). The 2030 Senior Notes were issued at par and resulted in proceeds of $490.0 million, after deducting underwriters’ discounts and commissions. The proceeds were used to repay a portion of the outstanding borrowings under the RBL Credit Agreement and fund a portion of the cash consideration for the Bedrock Acquisition, with the remainder of the purchase price being funded with shares of our common stock. In connection with the issuance of the 2030 Senior Notes, we recorded debt issuance costs of $13.6 million, which are amortized to interest expense on the consolidated statements of operations over the term of the 2030 Senior Notes.

Interest on the 2030 Senior Notes is payable semi-annually on April 15 and October 15 of each year, commencing on April 15, 2026. The 2030 Senior Notes are guaranteed on a senior unsecured basis by us and all of BKV Upstream Midstream’s existing restricted subsidiaries and certain future subsidiaries. These guarantees are full, unconditional, joint, and several among the guarantors of the 2030 Senior Notes, subject to certain customary release provisions. The indenture governing the 2030 Senior Notes contains customary events of default, as well as cross-default provisions with other indebtedness of BKV Upstream Midstream and its restricted subsidiaries.

On or after October 15, 2027, BKV Upstream Midstream may, on any one or more occasions, redeem some or all of its 2030 Senior Notes prior to their maturity at redemption prices plus accrued and unpaid interest as described in the indenture governing the 2030 Senior Notes. BKV Upstream Midstream may redeem up to 40% of the aggregate principal amount of the 2030 Senior Notes before October 15, 2027, with an amount of cash not greater than the net cash proceeds from certain equity offerings at a redemption price described in the indenture governing the 2030 Senior Notes plus accrued and unpaid interest to, but excluding, the redemption date. In addition, prior to October 15, 2027, BKV Upstream Midstream may redeem some or all of the 2030 Senior Notes at a price equal to 100% of the principal amount thereof, plus a make-whole premium as described in the indenture governing the 2030 Senior Notes, plus accrued and unpaid interest.

***Loan Agreements and Credit Facilities***

*RBL Credit Agreement*

On June 11, 2024, BKV Corporation, as a 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. On September 22, 2025, with the unanimous consent of the RBL Credit Agreement's lenders, we amended the RBL Credit Agreement to, among other things, increase the borrowing base by $150.0 million and the elected commitment by $135.0 million upon closing of the Bedrock Acquisition (among other conditions). This amendment constituted a semiannual borrowing base redetermination. As of December 31, 2025, the RBL Credit Agreement had a borrowing base of $1.0 billion, an elected commitment of $800.0 million, and the ability to issue up to $40.0 million in letters of credit.

The loans under the RBL Credit Agreement 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 senior secured basis by 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. During the years ended December 31, 2025 and 2024, BKV Upstream Midstream recognized $2.5 million and $0.8 million, respectively, of commitment fees, which are included in interest expense on the consolidated statements of operations. As of March 6, 2026, the filing date of our Original Form 10-K, $110.0 million of revolving borrowings and $15.0 million of letters of credit were outstanding under the RBL Credit Agreement, leaving $675.0 million of available capacity thereunder for future borrowings and letters of credit.

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.

The RBL Credit Agreement requires BKV Upstream Midstream and its restricted subsidiaries to always hedge not less than 50% of reasonably anticipated projected production from their proved developed producing reserves for the subsequent 24 calendar month period immediately following the date financial statements are required to be delivered under the RBL Credit Agreement for each fiscal quarter.

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 (subject to certain limitations in the RBL

Credit Agreement). As of December 31, 2025, BKV Upstream Midstream was in compliance with such covenants in 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.

Financing costs related to the RBL Credit Agreement are deferred and capitalized as debt issuance costs and are included within other assets on the consolidated balance sheets. As of December 31, 2025 and 2024, unamortized debt issuance costs were $6.9 million in each period.

*Revolving Credit Agreements and Term Loan Credit Agreement*

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 Loan Agreements and Credit Facilities***

*Temple I Loan Agreements*

On October 14, 2021, BKV-BPP Power entered into a Loan Agreement (the "$141 Million Banpu Loan Agreement") with BNAC, which allowed for a single drawdown in the amount of $141.0 million. On November 1, 2021, BKV-BPP Power borrowed $141.0 million under the $141 Million Banpu Loan Agreement for the purpose of acquiring Temple I and working capital.

On October 15, 2021, BKV-BPP Power entered into a Loan Agreement (the "$141 Million BPPUS Loan Agreement" and, together with the $141 Million Banpu Loan Agreement, the "Temple I Loan Agreements") with BPPUS, which allowed for a single drawdown in the amount of $141.0 million. On November 21, 2021, BKV-BPP Power borrowed $141.0 million under the $141 Million BPPUS Loan Agreement (and in addition to the $141.0 million borrowed under the $141 Million Banpu Loan Agreement) for the purpose of acquiring Temple I and working capital.

BKV-BPP Power's payment obligations under the Temple I Loan Agreements are senior unsecured indebtedness. The Temple I Loan Agreements bear interest at 6-month SOFR plus 5.25% per annum. Interest on the loans is payable on a semi-annual basis, and the loans will mature on November 1, 2026. BKV-BPP Power is permitted to prepay the loans at any time, with no prepayment premium. The Temple I Loan Agreements include covenants that, among other things, prohibit BKV-BPP Power from merging, incurring liens or incurring any additional indebtedness or guarantees. The Temple I Loan Agreements include financial covenants that require BKV-BPP Power to maintain a minimum net worth (as defined in the Temple I Loan Agreements, but generally meaning total assets minus total liabilities). In the $141 Million Banpu Loan Agreement, the minimum net worth requirement is $120.0 million and in the $141 Million BPPUS Loan Agreement, the minimum net worth requirement is $40.0 million. Under the Temple I Loan Agreements, BNAC and BPPUS have no recourse to BKV Corporation with respect to any amounts owed to them thereunder and BKV Corporation is not liable in any manner (and is not required to provide security) for any obligations owed to BNAC or BPPUS thereunder. As of December 31, 2025 and 2024, the outstanding principal balance of the Temple I Loan Agreements for each affiliate was $95.5 million and $105.0 million, respectively.

*Temple Credit Facilities*

On July 10, 2023, Temple Generation Intermediate Holdings II, LLC ("Temple Intermediate II"), an indirect subsidiary of BKV-BPP Power, as borrower, Temple Generation I, LLC ("Temple Generation I"), Temple Generation II, LLC ("Temple Generation II"), each of Temple Generation I and Temple Generation II being a subsidiary of Temple Intermediate II, and Temple Generation SF LLC ("Temple Generation SF"), a joint subsidiary of Temple Generation I and Temple Generation II, each as subsidiary guarantors, entered into a credit agreement (the "Beal Credit Agreement") with Beal Bank USA and the other lenders from time to time party thereto that provides the following credit facilities (collectively, the "Temple Credit Facilities"): (i) a senior secured term loan facility with an aggregate principal amount of $500.0 million (the "Temple Term Loan Facility"), which was fully drawn in an amount equal to $500.0 million on the closing date, and (ii) a senior secured revolving credit facility in the aggregate principal amount not to exceed $60.0 million (the "Temple Revolving Facility"), which was fully drawn in an amount equal to $60.0 million on the closing date. The interest is payable annually for the Temple Credit Facilities at a rate equal to SOFR plus an interest rate margin of 4.60%.

The Temple Term Loan Facility requires a quarterly repayment at a minimum of $2.5 million per quarter, beginning on September 30, 2023. The final aggregate principal installment for the Temple Term Loan Facility is due and payable on July 10, 2028 (subject to extension by up to two additional one-year periods), and the Temple Revolving Facility terminates five business days prior to the Temple Term Loan Facility maturity date. On the closing date, Temple Intermediate II applied the proceeds of the Temple Term Loan Facility to fund a portion of the Temple II acquisition and applied the proceeds of the Temple Revolving Facility for general corporate purposes, including working capital and operating expenses. Any prepayment of the Temple Term Loan Facility prior to the third anniversary of the closing date thereof is subject to a prepayment penalty. Amounts repaid by Temple Intermediate II with respect to the Temple Term Loan Facility may not be reborrowed. Amounts repaid by Temple Intermediate II with respect to the Temple Revolving Facility may be reborrowed upon satisfaction of customary conditions.

The obligations under the Temple Credit Facilities are secured by (i) all of the assets of Temple Intermediate II, Temple Generation I, Temple Generation II, and Temple Generation SF, including the Temple Plants and all other personal property and real property of such entities and (ii) 100.0% of the equity interests in each of Temple Generation I, Temple Generation II, Temple Generation SF, and Temple Intermediate II. This collateral will remain pledged to Beal Bank until all secured obligations under the Temple Credit Facilities have been satisfied in full. Upon the occurrence and continuation of an event of default under either of the Temple Credit Facilities, Beal Bank has customary secured creditor remedies, including the right to foreclose upon the pledged collateral.

As of December 31, 2025 and 2024, the weighted average effective interest rate on the outstanding balances under the RBL Credit Agreement, the Temple I Loan Agreements, and the Temple Credit Facilities was 8.86% and 8.79%, respectively.

***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, as applicable, we do not have the ability to unilaterally cause BKV-BPP Power or BKV-BPP Cotton Cove to make distributions. During the years ended December 31, 2025 and 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 each to us and BPPUS. 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, following the closing of the BKV-BPP Power Joint Venture Transaction on January 30, 2026, any additional capital contributions to BKV-BPP Power must be approved by a majority of BKV-BPP Power's twelve member board of managers, nine of whom are appointed by us and three of whom are appointed by BPPUS. Similarly, any additional capital contributions to BKV-BPP Cotton Cove must receive the unanimous approval of the BKV-BPP Cotton Cove Joint Venture's six-member board of managers, four of whom are appointed by us and two of whom are appointed by BPPUS.

On June 26, 2025, BKV dCarbon Ventures and BPPUS amended and restated the BKV-BPP Cotton Cove LLC Agreement whereby on July 9, 2025, BKV dCarbon Ventures contributed $3.3 million to BKV-BPP Cotton Cove, net of $0.1 million of expenditures paid by BKV dCarbon Ventures on behalf of BKV-BPP Cotton Cove, and on July 10, 2025, BPPUS received $5.4 million of its initial capital contribution of $8.6 million from BKV-BPP Cotton Cove. Subsequent to these transactions, BKV dCarbon Ventures contributed an additional $5.8 million, for a total of $9.0 million, and BPPUS contributed an additional $5.5 million, for a total of $8.8 million, for the year ended December 31, 2025.

On October 29, 2025, we entered into a Membership Interest Purchase Agreement with BPPUS to acquire one-half of the limited liability company interests of the BKV-BPP Power Joint Venture then held by BPPUS upon the terms and subject to the conditions of the purchase agreement.

On January 30, 2026, we completed the BKV-BPP Power Joint Venture Transaction for aggregate consideration consisting of $115.1 million in cash and 5,315,390 shares of our common stock. We funded the cash consideration with a combination of cash on hand and the net proceeds from the 2025 Equity Offering. For additional information, see *Note 13 - Stockholders' Equity and Mezzanine Equity*.

**Internal Controls and Procedures**

As an accelerated filer, we are required to comply with the SEC's rules implementing Section 404(a) of the Sarbanes-Oxley Act of 2002. Accordingly, management is required to assess, and report on the effectiveness of our internal control over financial reporting as of the end of each fiscal year, beginning with the Original Form 10-K. In addition, we are required to disclose any change in our internal control over financial reporting that occurred during the most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

**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, 2025, our material off-balance sheet arrangements and transactions included transportation commitments of $259.4 million and letters of credit of $15.0 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 *"—Liquidity and Capital Resources — 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.

***Accounting for Variable Interest Entities***

As described in *Note 14 - Investments* in our consolidated financial statements, on May 8, 2025, BKV dCarbon Ventures, together with C Squared Solutions, Inc., a subsidiary of the Energy Transition Fund managed by Copenhagen Infrastructure Partners (CIP), and for the limited purposes specified therein, BKV Corporation, entered into the BKV-CIP JV Agreement forming the BKV-CIP Joint Venture. On June 26, 2025, BKV dCarbon Ventures and BPPUS amended and restated the BKV-BPP Cotton Cove LLC Agreement whereby on July 9, 2025, BKV dCarbon Ventures contributed $3.3 million to BKV-BPP Cotton Cove, net of $0.1 million of expenditures paid by BKV dCarbon Ventures on behalf of BKV-BPP Cotton Cove, and on July 10, 2025, BPPUS received $5.4 million of its initial capital contribution of $8.6 million from BKV-BPP Cotton Cove. On July 31, 2025, BKV dCarbon Ventures and BPPUS contributed an additional $3.8 million and $3.6 million, respectively. BKV dCarbon Ventures owns a 51% interest and BPPUS owns a 49% interest in BKV-BPP Cotton Cove.

We consider the BKV-CIP Joint Venture and BKV-BPP Cotton Cove Joint Venture to each be a variable interest entity ("VIE") of BKV in accordance with Accounting Standards Codification ("ASC") 810, *Consolidation*, as BKV is deemed to be the primary beneficiary of these joint ventures. Generally, a VIE is an entity with at least one of the following conditions: (i) the total equity investment at risk is insufficient to allow the entity to finance its activities without additional subordinated financial support, or (ii) the holders of the equity investment at risk, as a group, lack the characteristics of having a controlling financial interest. The primary beneficiary of a VIE is an entity that has a variable interest or a combination of variable interests that provide such entity with a controlling financial interest in the VIE. An entity is deemed to have a controlling financial interest in a VIE if it has both of the following characteristics: (i) the power to direct the activities of the VIE that most significantly impact the VIE's economic performance, and (ii) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE.

In exchange for cash contributions received from the Class B Member to the BKV-CIP Joint Venture, the BKV-CIP Joint Venture has issued 1,791,155 Class B Units (the "Class B Units") at $10.00 per unit as of December 31, 2025. We determined that the Class B Units should be classified as noncontrolling interest within mezzanine equity on the Company's consolidated balance sheets. The Class B Units are not mandatorily redeemable or currently redeemable, but become exercisable with the passage of time, which is on the second anniversary of the BKV-CIP JV Agreement, or May 8, 2027. Prior to the second anniversary, we determined that there is an embedded put option in the Class B Units, which does not meet the derivative accounting criteria, and is not within the control of the Company. Therefore, the shares of the Class B Units have been classified as noncontrolling interest within mezzanine equity on our consolidated balance sheets. The redemption value of the Class B Units is based on a 1.65x multiple of invested capital, reduced by cumulative distributions made to the Class B Member. The contributions from the Class B Member are accreted to the redemption value over a period from issuance to the earliest redemption date (using the effective interest method) with the accretion accounted for as a dividend paid to the Class B Member.

***Recent Accounting Pronouncements***

See *Note 2 - Summary of Significant Accounting Policies* to our consolidated financial statements included in Item 8 of Part II, *Financial Statements and Supplementary Data* 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 in Section 2(a)(19) of the Securities Act of 1933, as amended, including as modified by the Jumpstart Our Business Startups Act of 2012 (the “JOBS Act”). As a result, for so long as we qualify as an emerging growth company, we are eligible to take advantage of certain exemptions from various reporting requirements applicable to other public companies that are not emerging growth companies. We elected to take advantage of certain of the reduced disclosure obligations in the Original 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 (i) we become a “large accelerated filer,” which requires that the market value of our common equity held by non-affiliates be at least $700 million as of the end of the most recently completed second fiscal quarter, (ii) our gross revenues for any fiscal year equal or exceed $1.235 billion, or (iii) we issue more than $1.0 billion of non-convertible debt in any three-year period, then we will cease to be an emerging growth company prior to the end of such five-year period. We expect to lose our emerging growth company status as of December 31, 2026.

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

***Commodity and Energy Price Risk and Hedging Activities***

As of December 31, 2025, we did not enter into any trading market risk sensitive instruments, and our market risk sensitive instruments consisted entirely of non-trading instruments entered into for risk management purposes related to our Upstream/Midstream segment’s natural gas and NGL production, and our Power segment, including power generation and retail power operations. Pricing for our natural gas, NGL, and power generation operations is primarily driven by prevailing regional market prices. Pricing for natural gas, NGLs and power has historically been volatile and unpredictable, and we expect this volatility to continue in the future. The prices we receive for the sale of our natural gas and NGL production, and that we pay for fuel and receive for sales of power in connection with our power generation business, each 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 and power prices, we enter into financial derivative instruments for a portion of our natural gas and NGL production, as well as a portion of the forecasted purchases and sales of fuel and power by our power business when management believes that favorable future prices can be secured.

Our financial hedging activities are intended to support natural gas, NGL, and power prices at targeted levels and to manage our exposure to natural gas, NGL and power 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, 2025 consisted of commodity swaps, basis swaps, put and call options, producer collar agreements, fixed-price natural gas forwards, fixed price power forwards, and HRCOs, subject to master netting agreements with each individual counterparty.

These derivative contracts cover portions of our projected positions through 2028. Our commodity hedge position as of December 31, 2025 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 aggregate notional volumes of these executed hedge instruments may not exceed certain limits without board of director approval of our forecasted production volumes. For the year ended December 31, 2025, a hypothetical increase of $0.10 per Mcf in NYMEX would have resulted in a $13.1 million decrease in natural gas hedge revenues, while a hypothetical decrease of $0.10 per Mcf in NYMEX would have resulted in a $13.2 million increase in natural gas hedge revenues. For the year ended December 31, 2025, a hypothetical increase or decrease of $1.00 per Bbl of NGL purity product price would have resulted in a $5.6 million decrease or increase in NGL hedge revenues, respectively.

Additionally, to reduce our exposure to fluctuations in the market price of power and natural gas, we 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 convert natural gas into power. We are exposed to basis risk in our operations when our derivative contracts are financially settled while physical power is delivered at different pricing locations or under different terms. For example, when we enter into an HRCO, we hedge our power production at an agreed price, but physical power must be delivered into the market it serves, which may result in pricing differences. Accordingly, we are exposed to basis risk between the hub price specified in the HRCO and the price received for power sales. These HRCOs are entered into to economically hedge power price and fuel cost exposures rather than for trading purposes. We attempt to hedge basis risk where possible, but hedging instruments are sometimes not economically feasible or available in the quantities that it requires. Our hedging activities do not provide us with protection for all of our basis risk and could result in economic losses and liabilities, which could have a material adverse effect 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 we are not able to satisfy our obligations under the HRCO, we 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 our business, financial condition, results of operations, and cash flows. During the year ended December 31, 2025, a hypothetical increase or decrease of $0.10 per MMBtu in Houston Ship Channel (HSC) natural gas daily prices would have resulted in a $0.7 million increase or decrease in Power segment hedge revenues, respectively.

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. Although these derivatives are not designated as accounting hedges for GAAP purposes, they are not entered into for trading or speculative purposes and are intended to manage commodity price and basis risk associated with our 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, 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, 2025, the estimated fair value of our commodity derivative instruments was a net asset of $76.1 million, comprised of current and noncurrent assets and current and noncurrent liabilities.

By removing price volatility from a portion of our expected production through December 2028, 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 creditworthiness 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, 2025, our primary exposure to interest rate risk was due to the balances on our Temple I Loan Agreements, the Temple Credit Facilities, and our RBL Credit Agreement, which have floating interest rates. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate 2030 Senior Notes, but can affect their fair values. For more information on our 2030 Senior Notes, see *Note 4 - Debt* and *Note 6 - Fair Value Measurements* to our consolidated financial statements. As of December 31, 2025, there were $191.0 million and $461.9 million of outstanding borrowings under the Temple I Loan Agreements and the Temple Credit Facilities, respectively, and we had no outstanding borrowings under our RBL Credit Agreement. The average annualized interest rate incurred on our outstanding variable rate borrowings during the year ended December 31, 2025, was approximately 8.18%. We estimate that a 1.0% increase in the applicable average interest rates during the year ended December 31, 2025 would have resulted in an increase of $8.7 million in interest expense.

**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, 2025 and 2024, and the related consolidated statements of operations, of equity and mezzanine equity and of cash flows for each of the three years in the period ended December 31, 2025, 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, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

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 6, 2026, except for the effects of an acquisition of a business between entities under common control and the change in the reportable segments discussed in Notes 1 and 19 to the consolidated financial statements, respectively, as to which the date is August 19, 2026

We have served as the Company's auditor since 2020.

**BKV Corporation**
**Consolidated Balance Sheets**
**(in thousands, except par value)**

| | December 31, 2025 | December 31, 2024 |
|---|---|---|
| Assets | | |
| Current assets | | |
| Cash and cash equivalents | $ 248,427 | $ 81,223 |
| Restricted cash | 15,846 | 15,775 |
| Accounts receivable, net | 129,077 | 71,680 |
| Accounts receivable, related parties | 11,196 | 14,877 |
| Prepaid expenses | 14,720 | 15,694 |
| Inventory | 20,039 | 20,130 |
| Commodity derivative assets, current | 63,900 | 8,884 |
| Other current assets | 8,150 | 6,718 |
| Total current assets | 511,355 | 234,981 |
| Natural gas properties and equipment | | |
| Developed properties | 2,965,638 | 2,315,167 |
| Undeveloped properties | 13,182 | 10,757 |
| Midstream assets | 277,974 | 276,644 |
| Accumulated depreciation, depletion, and amortization | (849,464) | (714,287) |
| Total natural gas properties, net | 2,407,330 | 1,888,281 |
| Other property, plant, and equipment, net | 944,412 | 936,797 |
| Deposits | 14,247 | 7,037 |
| Goodwill | 18,417 | 18,417 |
| Commodity derivative assets | 26,432 | — |
| Other noncurrent assets | 17,064 | 13,264 |
| Total assets | $ 3,939,257 | $ 3,098,777 |
| Liabilities, mezzanine equity, and equity | | |
| Current liabilities | | |
| Accounts payable and accrued liabilities | $ 229,487 | $ 162,524 |
| Contingent consideration payable | — | 20,000 |
| Commodity derivative liabilities, current | 8,469 | 40,093 |
| Income taxes payable to related party | 810 | 1,438 |
| Payable to BPPUS for the BKV-BPP Power Joint Venture Transaction | 115,136 | — |
| Current portion of Temple I Loan Agreements | 191,000 | — |
| Current portion of long-term debt, net | 9,387 | 9,387 |
| Other current liabilities | 10,302 | 3,263 |
| Total current liabilities | 564,591 | 236,705 |
| Asset retirement obligations | 230,372 | 198,795 |
| Commodity derivative liabilities | 5,767 | 47,586 |
| Payable to BPPUS for the BKV-BPP Power Joint Venture Transaction | — | 115,136 |
| Deferred tax liability, net | 128,839 | 92,750 |
| Noncurrent portion of Temple I Loan Agreements | — | 210,000 |
| Long-term debt, net | 937,724 | 639,816 |
| Other noncurrent liabilities | 5,223 | 5,469 |
| Total liabilities | 1,872,516 | 1,546,257 |
| Commitments and contingencies (Note 16) | | |
| Mezzanine equity | | |
| Noncontrolling interest | 12,951 | — |
| Stockholders' equity | | |
| Common stock, $0.01 par value; 500,000 authorized shares; 96,872 and 84,600 shares issued and outstanding as of December 31, 2025 and 2024, respectively | 1,635 | 1,512 |
| Treasury stock, shares at cost; 214 shares as of December 31, 2025 and 2024 | (6,663) | (6,663) |
| Additional paid-in capital | 1,681,785 | 1,374,525 |
| Retained earnings | 309,051 | 131,317 |
| Total stockholders' equity | 1,985,808 | 1,500,691 |
| Noncontrolling interest | 67,982 | 51,829 |
| Total equity | 2,053,790 | 1,552,520 |
| Total liabilities, mezzanine equity, and equity | $ 3,939,257 | $ 3,098,777 |

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

**BKV Corporation**
**Consolidated Statements of Operations**
**(in thousands, except per share amounts)**

| | Year Ended December 31, 2025 | 2024 | 2023 |
|---|---|---|---|
| Revenues and other operating income | | | |
| Natural gas, NGL, and oil sales | $ 857,597 | $ 557,570 | $ 706,151 |
| Midstream revenues | 10,456 | 12,560 | 16,168 |
| Power revenues | 248,752 | 218,268 | 274,623 |
| Derivative gains, net | 379,869 | 207,460 | 290,724 |
| Marketing revenues | 12,304 | 10,668 | 8,710 |
| Gain on sale of business | — | 7,080 | — |
| Gains (losses) on sales of assets, net | (1,805) | 3,523 | 2,207 |
| Section 45Q tax credits | 11,752 | 14,021 | 701 |
| Other | 11,664 | 6,631 | 3,957 |
| Total revenues and other operating income | 1,530,589 | 1,037,781 | 1,303,241 |
| Operating expenses | | | |
| Lease operating and workover | 152,873 | 136,991 | 150,647 |
| Fuel commodity costs | 180,364 | 118,662 | 94,213 |
| Purchased power | 113,968 | 108,327 | 27,769 |
| Taxes other than income | 66,407 | 47,852 | 81,117 |
| Gathering and transportation | 250,849 | 222,391 | 248,990 |
| Depreciation, depletion, amortization, and accretion | 195,737 | 255,500 | 255,122 |
| Power operating and maintenance | 78,435 | 81,071 | 56,365 |
| General and administrative | 131,572 | 110,031 | 133,574 |
| Other operating expenses | 56,674 | 21,194 | 14,296 |
| Total operating expenses | 1,226,879 | 1,102,019 | 1,062,093 |
| Income (loss) from operations | 303,710 | (64,238) | 241,148 |
| Other income (expense) | | | |
| Gains on contingent consideration liabilities | — | 9,676 | 38,375 |
| Interest expense | (72,316) | (96,221) | (95,472) |
| Interest expense, related parties | (19,669) | (27,496) | (32,072) |
| Interest income | 4,109 | 7,348 | 4,724 |
| Loss on early extinguishment of debt | — | (13,877) | — |
| Other income | 9,335 | 8,995 | 5,443 |
| Income (loss) before income taxes | 225,169 | (175,813) | 162,146 |
| Income tax benefit (expense) | (36,853) | 42,433 | (30,123) |
| Net income (loss) | 188,316 | (133,380) | 132,023 |
| Less: net income attributable to noncontrolling interest | 9,160 | 5,271 | 8,467 |
| Net income (loss) attributable to BKV | $ 179,156 | $ (138,651) | $ 123,556 |
| | | | |
| Net income (loss) per common share attributable to BKV: | | | |
| Basic | $ 2.05 | $ (1.94) | $ 2.03 |
| Diluted | $ 2.05 | $ (1.94) | $ 1.92 |
| | | | |
| Weighted average number of common shares outstanding: | | | |
| Basic | 86,581 | 71,288 | 60,730 |
| Diluted | 86,823 | 71,288 | 64,380 |

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

**BKV Corporation**
**Consolidated Statements of Cash Flows**
**(in thousands)**

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2025 | 2024 | 2023 |
| Cash flows from operating activities: | | | |
| Net income (loss) | $ 188,316 | $ (133,380) | $ 132,023 |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | | |
| Depreciation, depletion, amortization, and accretion | 197,225 | 255,859 | 256,179 |
| Equity-based compensation expense | 12,845 | 16,316 | 25,756 |
| Deferred income tax expense (benefit) | 37,857 | (43,639) | 34,292 |
| Unrealized (gains) losses on derivatives, net | (117,974) | 82,617 | (74,947) |
| Gains on contingent consideration liabilities | — | (9,676) | (38,375) |
| Settlement of contingent consideration | (20,000) | (20,000) | (65,000) |
| Payments for the purchase of put options | (16,206) | — | — |
| Proceeds from the sale of call options | — | 23,502 | — |
| Write-off of capitalized software costs | 5,643 | — | — |
| Gain on sale of business | — | (7,080) | — |
| (Gains) losses on sale of assets, net | 1,805 | (3,523) | (2,048) |
| Transaction costs from sale of business | — | (3,461) | — |
| Loss on early extinguishment of debt | — | 13,877 | — |
| Other, net | 8,256 | (789) | 4,042 |
| Changes in operating assets and liabilities: | | | |
| Accounts receivable, net | (46,829) | (12,956) | 86,120 |
| Accounts receivable, related party | 3,812 | (14,812) | (143) |
| Accounts payable and accrued liabilities | 28,256 | (27,883) | (90,902) |
| Other changes in operating assets and liabilities | (2,632) | 438 | (6,729) |
| Net cash provided by operating activities | 280,374 | 115,410 | 260,268 |
| Cash flows from investing activities: | | | |
| Asset acquisition | (272,096) | — | (480,261) |
| Cash acquired in consolidation of BKV-BPP Cotton Cove | 2,077 | — | — |
| Capital expenditures | (305,119) | (105,361) | (201,513) |
| Proceeds from sale of business | — | 132,571 | — |
| Proceeds from sales of assets | 6,876 | 5,060 | 3,312 |
| Proceeds from insurance claim | — | 2,645 | 8,344 |
| Other investing activities, net | (8,095) | (649) | 7,011 |
| Net cash provided by (used in) investing activities | (576,357) | 34,266 | (663,107) |
| 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 issuance of common stock, net of underwriting discounts and commissions | 170,635 | — | 150,005 |
| Proceeds on long-term debt | 500,000 | — | — |
| Payment of debt issuance costs | (15,869) | (8,054) | (3,065) |
| Proceeds under Temple Revolving Facility | — | — | 60,000 |
| Payments under Temple Term Loan Facility | — | — | 500,000 |
| Payments on Temple Term Loan Facility | (24,482) | (10,000) | (63,635) |
| Payments on Temple I Loan Agreements | (19,000) | — | (43,800) |
| Proceeds under RBL Credit Agreement | 577,000 | 580,000 | — |
| Payments on RBL Credit Agreement | (742,000) | (415,000) | — |
| Payment on term loan agreement | — | (456,000) | (114,000) |
| Payments on notes payable to related party | — | (75,000) | — |
| Proceeds on Power Plant Loan | — | — | 10,000 |
| Payment on Power Plant Loan | — | — | (10,000) |
| Proceeds from draws on credit facilities | — | 44,000 | 375,500 |
| Payments on credit facilities | — | (171,000) | (338,500) |
| Payments of deferred offering costs | — | (3,879) | (2,901) |
| Debt extinguishment costs | — | (10,213) | — |
| Distributions to noncontrolling interest | — | — | (10,000) |
| Net share settlements, equity-based compensation | (1,619) | (53,239) | (2,961) |
| Cash distributions to noncontrolling interest | (1,225) | — | — |
| Cash contributions from noncontrolling interest | 19,818 | — | — |
| Other financing activities | — | (2,081) | (8,155) |
| Net cash provided by (used in) financing activities | 463,258 | (314,805) | 498,488 |
| Net increase (decrease) in cash, cash equivalents, and restricted cash | 167,275 | (165,129) | 95,649 |
| Cash, cash equivalents, and restricted cash, beginning of period | 96,998 | 262,127 | 166,478 |
| Cash, cash equivalents, and restricted cash, end of period | $ 264,273 | $ 96,998 | $ 262,127 |

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

**BKV Corporation**
**Consolidated Statements of Cash Flows**
**(in thousands)**

| **Supplemental cash flow information:** | **Year Ended December 31,** 2025 | 2024 | 2023 |
|---|---|---|---|
| Cash payments for: | | | |
| Interest | $ 59,451 | $ 94,492 | $ 94,069 |
| Interest, related parties | $ 20,140 | $ 39,270 | $ 25,912 |
| Income tax | $ 232 | $ 6 | $ 1,545 |
| Non-cash investing and financing activities: | | | |
| Equity issued as consideration for acquisition | $ 124,254 | $ — | $ — |
| 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 | $ 1,768 | $ 10,469 | $ — |
| Reclassification of deferred offering costs to additional paid-in capital upon initial public offering | $ — | $ 11,649 | $ — |
| Increase (decrease) in accrued capital expenditures | $ 18,204 | $ 16,850 | $ (23,178) |
| Additions to asset retirement obligations | $ 226 | $ 42 | $ 89 |
| Lease liabilities arising from obtaining right-of-use assets | $ 23 | $ 494 | $ 3,061 |
| Increase (decrease) in accrued equity transaction costs | $ 501 | $ (341) | $ (604) |
| Adjustment of minority ownership puttable shares to redemption value | $ — | $ 16,989 | $ 2,722 |
| Adjustment of equity-based compensation to redemption value | $ — | $ 9,310 | $ 15,602 |
| 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 |
| Accretion of Class B Units to redemption value | $ 1,422 | $ — | $ — |
| Distributions payable to noncontrolling interest | $ 6,870 | $ — | $ — |

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

# BKV Corporation
## Consolidated Statements of Equity and Mezzanine Equity
## (in thousands)

| | Equity | | | | | | | | Mezzanine Equity | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Common Stock | | Treasury | | Additional Paid-In Capital | Retained Earnings | Noncontrolling Interest | Total Equity | Common Stock | | Equity-based Compensation | Noncontrolling Interest | Total Mezzanine Equity |
| | Shares | Amount | Shares | Amount | | | | | Shares | Amount | | | |
| **Balance, December 31, 2022** | **56,373** | **$ 1,132** | **193** | **$ (3,974)** | **$ 823,288** | **$ 146,412** | **$ 48,091** | **$ 1,014,949** | **2,290** | **$ 62,712** | **$ 89,171** | **$ —** | **$ 151,883** |
| Net income | — | — | — | — | — | 123,556 | 8,467 | 132,023 | — | — | — | — | — |
| 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) | — | — | — | — | — |
| Distributions to noncontrolling interest | — | — | — | — | — | — | (10,000) | (10,000) | — | — | — | — | — |
| Equity-based compensation | — | — | — | — | — | — | — | — | — | — | 25,756 | — | 25,756 |
| **Balance, December 31, 2023** | **63,873** | **$ 1,283** | **213** | **$ (4,582)** | **$ 960,999** | **$ 269,968** | **$ 46,558** | **$ 1,274,226** | **2,403** | **$ 59,988** | **$ 126,966** | **$ —** | **$ 186,954** |
| Net loss | — | — | — | — | — | (138,651) | 5,271 | (133,380) | — | — | — | — | — |
| 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 | — | — | — | — | — |
| Mezzanine equity conversion | 5,026 | 71 | — | — | 117,917 | — | — | 117,988 | (5,026) | (42,995) | (74,993) | — | (117,988) |
| Income tax deconsolidation | — | — | — | — | 10,469 | — | — | 10,469 | — | — | — | — | — |
| Equity-based compensation | — | — | — | — | 3,663 | — | — | 3,663 | — | — | 12,653 | — | 12,653 |
| **Balance, December 31, 2024** | **84,600** | **$ 1,512** | **214** | **$ (6,663)** | **$ 1,374,526** | **$ 131,317** | **$ 51,829** | **$ 1,552,521** | **—** | **$ —** | **$ —** | **$ —** | **$ —** |
| Net income | — | — | — | — | — | 179,156 | 7,448 | 186,604 | — | — | — | 1,712 | 1,712 |
| Contributions from noncontrolling interest | — | — | — | — | — | — | 8,803 | 8,803 | — | — | — | 17,912 | 17,912 |
| Distributions to noncontrolling interest | — | — | — | — | — | — | — | — | — | — | — | (1,225) | (1,225) |
| Changes due to consolidation of BKV-BPP Cotton Cove | — | — | — | — | — | — | (98) | (98) | — | — | — | — | — |
| Accretion of Class B Units to redemption value | — | — | — | — | — | (1,422) | — | (1,422) | — | — | — | 1,422 | 1,422 |
| Distribution declared to noncontrolling interest | — | — | — | — | — | — | — | — | — | — | — | (6,870) | (6,870) |
| Issuance of common stock, net | 12,134 | 121 | — | — | 294,267 | — | — | 294,388 | — | — | — | — | — |
| Common stock issued upon vesting of RSUs, net of shares withheld for income taxes | 138 | 2 | — | — | (1,621) | — | — | (1,619) | — | — | — | — | — |
| Income tax deconsolidation | — | — | — | — | 1,768 | | — | 1,768 | — | — | — | — | — |
| Equity-based compensation | — | — | — | — | 12,845 | — | — | 12,845 | — | — | — | — | — |
| **Balance, December 31, 2025** | **96,872** | **$ 1,635** | **214** | **$ (6,663)** | **$ 1,681,785** | **$ 309,051** | **$ 67,982** | **$ 2,053,790** | **—** | **$ —** | **$ —** | **$ 12,951** | **$ 12,951** |

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

**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 businesses are the production of natural gas and the generation of natural gas-fired power from our owned and operated assets.

The majority shareholder of BKV Corp is BNAC. BKV Corp's ultimate parent company is Banpu Public Company Limited ("Banpu"), a public company listed in the Stock Exchange of Thailand. As of March 6, 2026, Banpu, the ultimate parent company of BNAC and BPPUS, indirectly owned an aggregate 67.1% of BKV Corp's shares. The remaining 32.9% 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 and majority-owned subsidiaries in which BKV Corp has a controlling interest.

BKV-BPP Power, a Delaware limited liability company, was formed on July 30, 2021 to own and operate combined-cycle natural gas-fired power generation facilities and a retail electricity marketing business in Temple, Texas. BKV-BPP Power is a joint venture owned by BKV Corp and BPPUS. Following the closing of the BKV-BPP Power Joint Venture Transaction on January 30, 2026, the BKV-BPP Power Joint Venture is owned 75% by BKV and 25% by BPPUS. Because the BKV-BPP Power Joint Venture Transaction represented an acquisition of a business between entities under common control, the Company has retrospectively recast certain financial information and related disclosures included herein to include the historical results of the BKV-BPP Power Joint Venture for all periods beginning on July 30, 2021, which was the formation of the BKV-BPP Power Joint Venture when the Company and BKV-BPP Power first came under common control. See *Note 3 - Acquisition and Dispositions* for further discussion. The Company is also considered the primary beneficiary of BKV-BPP Power and consolidated BKV-BPP Power's financial results in accordance with ASC 810, *Consolidation*. See *Note 14 - Investments* for further discussion. This also caused the Company's reportable segments to change from one reportable segment and one operating segment to two reportable segments, consisting of Upstream/Midstream and Power and one operating segment, consisting of Corporate and Other, which is an "All Other" category that includes the CCUS business. See *Note 19 - Reportable Segments* for further discussion.

BKV-BPP Power and its direct and indirect wholly-owned subsidiaries, Temple Generation I, Temple Intermediate Holdings II, Temple Generation II, BKV-BPP Retail, and BKV-BPP Ponder Solar, own the power generation and related assets and retail energy business that comprise the Company's Power segment.

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. BKV Upstream Midstream and its wholly-owned subsidiaries, BKV Operating, LLC, BKV Barnett, LLC, BKV Chelsea, LLC ("Chelsea"), BKV Midstream, LLC, BKV North Texas, LLC, and Kalnin Ventures, LLC comprise the Company's Upstream/Midstream segment.

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 Chelsea. See *Note 3 - Acquisition and Dispositions* for further discussion.

On September 29, 2025, BKV Upstream Midstream acquired 100% of the equity interests of Bedrock Production, LLC (now known as BKV Barnett II, LLC ("BKV Barnett II")), a Texas limited liability company (such transaction, the "Bedrock Acquisition") from Bedrock Energy Partners, LLC (the "Seller"), pursuant to a Membership Purchase Agreement (the "Bedrock Purchase Agreement"). BKV Barnett II and its subsidiaries own certain oil and natural gas producing properties and midstream assets in the Barnett Shale. See *Note 3 - Acquisition and Dispositions* for further discussion.

Together, BKV Corp, its wholly-owned subsidiaries, and its majority-owned subsidiaries where BKV Corp has a controlling interest and is the primary beneficiary, 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.

***Reclassification***

Certain prior period amounts have been reclassified in order to conform to the current period presentation. These reclassifications had no impact on previously reported balance sheets, net income (loss), 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.

***Equity Offering***

On December 3, 2025, the Company completed its public offering of 6,900,000 shares of common stock for net proceeds of $170.1 million, which were used, together with cash on hand, for the payment of the cash consideration of the purchase price in connection with BKV’s acquisition of a controlling interest in BKV-BPP Power LLC and related expenses. See *Note 13 - Stockholders’ Equity and Mezzanine Equity* and *Note 14 - Investments* for further detail.

***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, 2025, the Company held $248.4 million of cash and cash equivalents. The Company’s working capital deficit as of December 31, 2025 was $53.2 million, and for the year ended December 31, 2025, cash flows provided by operating activities was $280.4 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, 2025, the Company purchased put options with several counterparties and paid a premium of $16.2 million. For further discussion on derivative transactions, see *Note 7 - Derivative Instruments*.

On September 26, 2025, BKV Upstream Midstream issued in a private placement $500.0 million of 7.50% senior unsecured notes due October 15, 2030 (the “2030 Senior Notes”). The 2030 Senior Notes were issued at par and resulted in proceeds of $490.0 million, after deducting underwriters’ discounts and commissions. The proceeds were used to repay a portion of the RBL Credit Agreement and fund a portion of the purchase price of the Bedrock Acquisition, with the remainder of the purchase price being funded with shares of BKV’s common stock. See *Note 4 - Debt* for further discussion on the RBL Credit Agreement and these transactions.

On September 29, 2025, BKV Upstream Midstream acquired 100% of the equity interests of BKV Barnett II from the Seller, and for the year ended December 31, 2025, paid total cash consideration of $266.5 million and transaction costs of $3.8 million. See *Note 3 - Acquisition and Dispositions* for further discussion.

**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 assets acquired and liabilities assumed 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, its wholly-owned subsidiaries, and its majority-owned subsidiaries where BKV Corp has a controlling interest and is the primary beneficiary. 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, 2025, 2024, and 2023. 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, 2025, 2024, and 2023, restricted cash included amounts to fund the debt service reserve account, or the quarterly portion due on the Temple Term Loan Facility (as defined below) plus accrued interest and cash collateral held in connection with certain retail customers. As of December 31, 2023, restricted cash also 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. The Term Loan Credit Agreement was repaid during the year ended December 31, 2024, eliminating the debt service reserve requirement on the Term Loan Credit Agreement. The following table provides a reconciliation of cash and cash equivalents and restricted cash to amounts shown on the consolidated statements of cash flows:

| | December 31, | | |
|---|---|---|---|
| **(in thousands)** | **2025** | **2024** | **2023** |
| Cash and cash equivalents | $ 248,427 | $ 81,223 | $ 105,012 |
| Restricted cash | 15,846 | 15,775 | 157,115 |
| Cash, cash equivalents, and restricted cash | $ 264,273 | $ 96,998 | $ 262,127 |

***Inventory***

Inventory primarily consists of materials and supplies and is 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 and remained deconsolidated from BNAC throughout the year ended December 31, 2025. 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, 2025 and 2024. 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, 2025, 2024, and 2023, 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, 2025, 2024, and 2023.

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, 2025, 2024, and 2023, 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, 2025, 2024, and 2023.

***Other Property, Plant, and Equipment***

Other property, plant, 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, plant, 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, plant, 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, 2025, 2024, and 2023.

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, plant, and equipment:

| | Useful Life |
|---|---|
| Buildings | 39 years |
| Plant facility | 15 to 30 years |
| Carbon capture, utilization, and sequestration | 12 years |
| Furniture, fixtures, equipment, vehicles, and other | 5 to 15 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, 2025 and 2024, all of the Company’s leases are accounted for as operating leases. For the years ended December 31, 2025, 2024, and 2023, total lease expense for the Company was $2.5 million, $1.3 million, and $1.7 million, respectively. These expenses are included in depreciation, amortization, depletion, and accretion, and lease operating and workover 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, 2025, 2024, and 2023, 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.

*Power Revenues*

Revenues consist of power generated out of the Temple Plants and sold to a third party at either market or negotiated contract terms. Revenue is based on an agreed upon amount which is equal to the quantity sold and the market index price as determined by ERCOT for the applicable period. Revenue is recognized once the performance obligation has been satisfied and control of the commodity has transferred to the customer at its agreed upon delivery location. It is then financially settled in the subsequent month. Physical transactions, or the sale of generated electricity to meet supply and demand to ERCOT, are recorded net of any physical power purchased.

BKV-BPP Retail also sells electricity to end user customers in the state of Texas. The Company considers the delivery of electricity to each customer a separate performance obligation that is satisfied upon delivery. The Company recognizes revenue that corresponds to the price of electricity delivered to the customer. The usage is determined by the customers' meter readings which occurs systematically throughout the month, and at the end of the month, the delivered usage is billed and recognized in revenues. Based on the last metered reading for the month, the Company estimates and accrues for any usage that hasn't been billed in unbilled revenues, which were $0.5 million, $5.1 million, and $3.0 million, for the years ended December 31, 2025, 2024, and 2023, respectively.

*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 and power generation. 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 and power generation. 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. The Section 45Q tax credits generated after the Company's IPO are included in accounts receivable on the consolidated balance sheets. Prior to the Company's IPO, the Section 45Q tax credits were recognized as accounts receivable, related party on the consolidated balance sheets. See *Note 9 - Related Parties* for further discussion.

***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 approximate fair value due to the short-term maturities of these instruments. In addition, as of December 31, 2025 and 2024, the carrying value of the Company's RBL Credit Agreement 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's goodwill is assigned to and tested for impairment at the Upstream/Midstream reporting unit. 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, 2025, 2024, and 2023. 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 units to be greater than the carrying value during the years ended December 31, 2025, 2024, and 2023.

***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.

***Variable Interest Entities***

The Company consolidates variable interest entities in which it is the primary beneficiary in accordance with ASC 810-*Consolidation*. Generally, a variable interest entity ("VIE") is an entity with at least one of the following conditions: (i) the total equity investment at risk is insufficient to allow the entity to finance its activities without additional subordinated financial support, or (ii) the holders of the equity investment at risk, as a group, lack the characteristics of having a controlling financial interest. The primary beneficiary of a VIE is an entity that has a variable interest or a combination of variable interests that provide such entity with a controlling financial interest in the VIE. An entity is deemed to have a controlling financial interest in a VIE if it has both of the following characteristics: (i) the power to direct the activities of the VIE that most significantly impact the VIE's economic performance, and (ii) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE.

***Net Income (Loss) Per Common Share***

Basic net income (loss) per common share attributable to BKV for each period is calculated by dividing net income (loss) attributable to BKV, adjusted for accretion to redemption value of the Class B Units, by the basic weighted average number of common shares outstanding during the period. Diluted net income (loss) per common share attributable to BKV is calculated by dividing net income (loss) attributable to BKV, adjusted for accretion to redemption value of the Class B Units, by the diluted weighted average number of common shares outstanding for the respective period. Any remeasurement of the accretion to redemption value of the Class B Units subject to possible redemption was considered to be dividends paid to the Class B Member. Accordingly, accretion is deducted from net income (loss) in the calculation of earnings per share. 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.

***Recently Adopted Accounting Standards***

In December 2023, the FASB issued ASU No. 2023-09, Income Taxes: Improvements to Income Tax Disclosures, which requires disaggregation of certain components included in the Company's effective tax rate and income taxes paid disclosures. The Company adopted this guidance during the year ended December 31, 2025. See *Note 17 - Income Taxes* for further detail.

***Recent Accounting Pronouncements Not Yet Adopted***

In November 2024, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("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 for fiscal years beginning after December 15, 2026 and interim periods within fiscal years beginning after December 15, 2027, with early adoption permitted as of the beginning of a fiscal year. Management is currently evaluating the impact this standard will have on the Company's disclosures.

In September 2025, the FASB issued ASU 2025-06, *Targeted Improvements to the Accounting for Internal-Use Software*. Under the new standard, companies may capitalize eligible costs when (i) management has authorized and committed to funding the software project, and (ii) it is probable that the project will be completed and the software will be used to perform the function intended. The standard is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2027, with early adoption permitted as of the beginning of a fiscal year. The standard may be applied prospectively, retrospectively or using a modified transition approach. The Company is currently evaluating the impact that this standard will have on the Company's consolidated operating results, cash flows, financial condition, and related disclosures.

**Note 3 - Acquisition and Dispositions**

***BKV-BPP Power Joint Venture Transaction***

On January 30, 2026, pursuant to the BKV-BPP Power Purchase Agreement, the Company completed the BKV-BPP Power Joint Venture Transaction, which consisted of $115.1 million in cash and 5,315,390 shares of Company common stock. The shares were subject to a 180-day lock-up that expired on July 29, 2026. The aggregate purchase price was equal to (x) $376.0 million, less (y) 25% of BKV-BPP Power's net indebtedness at closing, payable 50% in cash and 50% in shares of the Company's common stock. BKV-BPP Power's net indebtedness was $582.9 million as of the closing date and the number of shares issued was determined by dividing the 50% of the aggregate purchase price by $21.6609, which represents the volume-weighted average price of the Company's common stock during the 20 consecutive trading day period ended October 28, 2025. The Company funded the cash consideration for the transaction with a combination of cash on hand and the net proceeds from the 2025 Equity Offering. Following the closing of the transaction, the Company and BPPUS own 75% and 25% of the BKV-BPP Power Joint Venture, respectively.

The Company's consolidated financial statements include $15.8 million of costs associated with the BKV-BPP Power Joint Venture Transaction. Of this amount, $9.3 million related to the 2025 Equity Offering, and was recorded as a reduction of additional paid-in capital. Transaction costs of $6.5 million were expensed during the year ended December 31, 2025, and included in other operating expenses on the consolidated statements of operations.

The BKV-BPP Power Joint Venture Transaction was accounted for as an acquisition of a business between entities under common control (see *Note 1 - Business and Basis of Presentation* for further information). Accordingly, the consolidated financial statements prior to the acquisition date were retrospectively recast to include the BKV-BPP Power Joint Venture's historical results, including reflecting BPPUS's interest as a noncontrolling interest of 25%. The Company previously accounted for BKV-BPP Power as an equity method investment and recognized 50% of its earnings.

The following table represents a summary of the retrospective adjustments to the consolidated statements of operations for the years ended December 31, 2025, 2024, and 2023 to conform to the current presentation due to the BKV-BPP Power Joint Venture Transaction.

| | Year Ended December 31, | | |
|---|---|---|---|
| **(in thousands)** | **2025** | **2024** | **2023** |
| Increase to net income | | | |
| Income from operations | $ 86,097 | $ 90,563 | $ 83,528 |
| Net income | 13,472 | 9,490 | 15,105 |
| Less: net income attributable to noncontrolling interest | 7,448 | 5,271 | 8,467 |
| Net income (loss) attributable to BKV | $ 6,024 | $ 4,219 | $ 6,638 |
| | | | |
| Net income (loss) per common share attributable to BKV: | | | |
| Basic | $ 0.07 | $ 0.06 | $ 0.11 |
| Diluted | $ 0.07 | $ 0.06 | $ 0.10 |
| | | | |
| Weighted average number of common shares outstanding: | | | |
| Basic | 86,581 | 71,288 | 60,730 |
| Diluted | 86,823 | 71,288 | 64,380 |

This retrospective presentation is an accounting convention and does not alter the legal ownership interests in the BKV-BPP Power, or the related rights to BKV-BPP Power's income and net assets that existed before the closing date of the BKV-BPP Power Joint Venture Transaction.

The retrospective combination of BKV-BPP Power therefore does not imply that the Company or the holders of its common shares other than Banpu and its affiliates had legal or economic rights to the additional 25% interest before January 30, 2026. Prior to the closing date of the BKV-BPP Power Joint Venture Transaction, Banpu's indirect economic interest in the additional 25% interest was held through BPPUS rather than through the Company. Accordingly, for periods before January 30, 2026, the BKV-BPP Power Joint Venture's net income and net assets were attributed based on the legal ownership interests in effect during those periods. For purposes of the retrospective earnings per share presentation, the per share amounts applicable to common shares held, directly or indirectly, by Banpu reflect Banpu's historical economic interest in the transferred 25% interest. The per share amounts applicable to the Company's other common shareholders reflect only the economic interests held through the Company during those periods.

Accordingly, for the year ended December 31, 2025, both basic and diluted earnings per common share were $2.11 for common shares held by Banpu and $1.98 for common shares held by the Company's other shareholders. For the year ended December 31, 2024, both basic and diluted earnings per common share were $(1.92) for common shares held by Banpu and $(2.02) for common shares held by the Company's other shareholders. For the year ended December 31, 2023, basic and diluted earnings per common share were $2.04 and $1.92, respectively, for common shares held by Banpu and $1.90 and $1.79, respectively, for common shares held by the Company's other shareholders. Beginning on January 30, 2026, earnings associated with the acquired 25% interest are available to all of the Company's common shares. The tables below summarize these attribution principles.

| | December 31, | |
|---|---|---|
| **(in thousands)** | **2025** | **2024** |
| Noncontrolling interest in BKV-BPP Power | $ 64,277 | $ 56,829 |
| BKV's interest in BKV-BPP Power | 192,830 | 170,488 |
| Net assets attributable to common shareholders | 43,785 | 27,840 |
| Net assets attributable to Banpu | 127,153 | 128,727 |

| (in thousands, except per share amounts) | Year Ended December 31, 2025 | 2024 | 2023 |
|---|---|---|---|
| BKV-BPP Power net income attributable to noncontrolling interest | $ 7,448 | $ 5,271 | $ 8,467 |
| BKV-BPP Power net income attributable to BKV | $ 22,342 | $ 15,814 | $ 25,401 |
| BKV-BPP Power net income attributable to common shareholders | $ 5,073 | $ 2,582 | $ 613 |
| BKV-BPP Power net income attributable to Banpu | $ 14,733 | $ 11,940 | $ 24,482 |
| | | | |
| Net income (loss) attributable to common shareholders | $ 58,483 | $ (35,253) | $ 4,165 |
| Net income (loss) attributable to Banpu | $ 120,673 | $ (103,398) | $ 119,391 |
| | | | |
| Net income (loss) per common share attributable to common shareholders: | | | |
| Basic | $ 1.98 | $ (2.02) | $ 1.90 |
| Diluted | $ 1.98 | $ (2.02) | $ 1.79 |
| Net income (loss) per common share attributable to Banpu: | | | |
| Basic | $ 2.11 | $ (1.92) | $ 2.04 |
| Diluted | $ 2.11 | $ (1.92) | $ 1.92 |
| | | | |
| Weighted average number of common shares outstanding attributable to common shareholders: | | | |
| Basic | 29,489 | 17,462 | 2,198 |
| Diluted | 29,572 | 17,462 | 2,330 |
| Weighted average number of common shares outstanding attributable to Banpu: | | | |
| Basic | 57,092 | 53,826 | 58,532 |
| Diluted | 57,251 | 53,826 | 62,050 |

As a result of the consolidation of BKV-BPP Power, the Company determined that the manner in which its Chief Executive Officer, identified as the Chief Operating Decision Maker (“CODM”), evaluates operating performance and allocates resources has changed. Accordingly, BKV-BPP Power, the Company’s power generation business, meets the criteria to be presented as a reportable segment. See *Note 19 - Reportable Segments*.

***Asset Acquisition***

*Bedrock Acquisition*

On September 29, 2025 in connection with the Bedrock Acquisition, the Company paid a portion of the purchase price consisting of (i) a $37.0 million deposit retained as a holdback for any Company indemnification claims until released on the terms and conditions contained in the Bedrock Purchase Agreement, (ii) $179.5 million in cash to repay certain indebtedness of BKV Barnett II, and (iii) the issuance to the Seller of approximately 5.2 million shares of BKV Corporation common stock with such number of shares having been determined as of the date of execution of the Bedrock Purchase Agreement. On December 31, 2025, the remaining purchase price consideration paid was $50.0 million, subject to the terms and conditions of the Bedrock Purchase Agreement. The Bedrock Purchase Agreement has an economic effective date of July 1, 2025.

The Company funded the cash consideration paid at the closing of the Bedrock Acquisition, and expects to fund the remainder of the consideration payable, with proceeds from the 2030 Senior Notes, borrowings under the RBL Credit Agreement, and cash on hand. Refer to *Note 4 - Debt* for further information.

As a result of the Bedrock Acquisition, the Company acquired approximately 96,000 net acres and gas gathering lines, 1,121 producing locations with low 1- and 5-year base decline rates of approximately 7%, and nearly 1 Tcfe of proved reserves (>70% PDP reserves) using NYMEX strip pricing. The Bedrock Acquisition is expected to increase the Company’s low-declining PDP reserves by over 100 MMcfe/d and enhance its inventory in the Barnett Shale, aligning with the Company’s strategic position in the Fort Worth Basin.

*Allocation of Purchase Price.* The Bedrock Acquisition was accounted for as an asset acquisition as the fair value of substantially all the assets acquired were concentrated in a group of similar assets. Transaction costs incurred to acquire the assets, which amounted to $3.8 million, were capitalized and included in the cost basis of the acquired assets. The Company completed the purchase price assessment on December 31, 2025, and paid the remaining $50.0 million adjusted purchase price consideration in accordance with the Bedrock Purchase Agreement. The stock consideration paid to the Seller for the Bedrock Acquisition was valued at $124.3 million on the date of issuance (at closing) resulting in an aggregate value of consideration paid to the Seller of $394.6 million, subject to customary adjustments, including, but not limited to estimated fair value of assets acquired and liabilities assumed. See *Note 13 - Stockholders' Equity and Mezzanine Equity* for further detail on the issuance of BKV's common stock to the Seller.

Below is a reconciliation of the assets acquired and liabilities assumed (in thousands):

| | | |
|---|---|---|
| **Consideration:** | | |
| Cash | $ | 266,535 |
| Capitalized transaction costs | $ | 3,761 |
| Shares of BKV Corporation's common stock | | 5,233,957 |
| BKV common stock price | $ | 23.74 |
| Total stock consideration | $ | 124,254 |
| Total consideration | $ | 394,550 |
| **Assets acquired and liabilities assumed** | | |
| Accounts receivable, net | $ | 15,324 |
| Commodity derivative assets, current | | 10,508 |
| Developed properties | | 390,826 |
| Commodity derivative assets | | 12,839 |
| Other noncurrent assets | | 6,392 |
| Accounts payable and accrued liabilities | | (13,416) |
| Commodity derivative liabilities, current | | (2,636) |
| Other current liabilities | | (5,024) |
| Asset retirement obligations | | (18,761) |
| Other noncurrent liabilities | | (1,502) |
| Total net assets acquired | $ | 394,550 |

*Temple II Acquisition*

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 ERCOT North Zone in Temple, Texas, for a purchase price of $460.0 million. Temple II began commercial operation in May 2015 and is equipped with modern, flexible and efficient combined-cycle turbines and advanced emissions-control technology. Temple II provides enough energy to power 750,000 homes across central Texas.

In order to complete the purchase, BKV-BPP Power entered into the Temple Credit Facilities with an aggregate principal amount not to exceed $560.0 million. See *Note 4 - Debt* for further discussion.

The acquisition qualified as an asset acquisition as the fair value of substantially all the assets acquired were concentrated in a group of similar assets. Transaction costs incurred to acquire the assets, which amounted to $9.5 million were capitalized and included in the cost basis of the assets acquired. The total consideration of Temple II amounted to $475.4 million, which included the purchase price of $460.0 million, the transaction cost of $9.5 million, and net working capital of $5.9 million.

The consideration from the Temple II acquisition was allocated to the assets acquired and liabilities assumed as follows:

| (in thousands) | | |
|---|---|---|
| Assets acquired | | |
| Accounts receivable | $ | 3,320 |
| Prepaid and other assets | | 6,631 |
| Other property, plant, and equipment | | 471,318 |
| Liabilities assumed | | |
| Accounts payable and accrued liabilities | | (3,180) |
| Property taxes payable | | (2,717) |
| Total | $ | 475,372 |

***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 $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 $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.

**Note 4 - Debt**

The following table summarizes the Company's debt balances:

| | December 31, | | | |
|---|---|---|---|---|
| | 2025 | | 2024 | |
| (in thousands) | Principal Value | Carrying Value | Principal Value | Carrying Value |
| Current portion of Temple I Loan Agreements | $ 191,000 | $ 191,000 | $ — | $ — |
| Current portion of Temple Term Loan Facility | 10,000 | 9,387 | 10,000 | 9,387 |
| Total current portion of long-term debt, net | 201,000 | 200,387 | 10,000 | 9,387 |
| Temple I Loan Agreement | — | — | 210,000 | 210,000 |
| RBL Credit Agreement | — | — | 165,000 | 165,000 |
| 2030 Senior Notes (7.50%) | 500,000 | 486,777 | — | — |
| Temple Term Loan Facility | 391,883 | 390,947 | 416,365 | 414,816 |
| Temple Revolving Facility | 60,000 | 60,000 | 60,000 | 60,000 |
| Total debt, net | 1,152,883 | 1,138,111 | 861,365 | 859,203 |
| Less: current maturities of long-term debt | (201,000) | (200,387) | (10,000) | (9,387) |
| Total long-term debt, net | $ 951,883 | $ 937,724 | $ 851,365 | $ 849,816 |

During the year ended December 31, 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. Also, 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.

***2030 Senior Notes***

On September 26, 2025, BKV Upstream Midstream issued in a private placement $500.0 million of the 2030 Senior Notes. The 2030 Senior Notes were issued at par and resulted in proceeds of $490.0 million, after deducting underwriters' discounts and commissions. The proceeds were used to repay a portion of the RBL Credit Agreement and fund a portion of the purchase price of the Bedrock Acquisition. In connection with the issuance of the 2030 Senior Notes, the Company paid debt issuance costs of $13.6 million, which are amortized to interest expense on the Company's consolidated statements of operations over the term of the 2030 Senior Notes. As of December 31, 2025, the effective interest rate on the 2030 Senior Notes was 8.31%.

Interest on the 2030 Senior Notes is payable semi-annually on April 15 and October 15 of each year, commencing on April 15, 2026. The 2030 Senior Notes are guaranteed on a senior unsecured basis by the Company and all of BKV Upstream Midstream's existing restricted subsidiaries and certain future subsidiaries (collectively, the "BKV Guarantors," and such guarantees, the "Guarantees"). These Guarantees are full, unconditional, joint, and several among the BKV Guarantors, subject to certain customary release provisions. At any time prior to October 15, 2027, BKV Upstream Midstream may, on any one or more occasions, redeem all or a part of the 2030 Senior Notes at a redemption price equal to 100% of the principal amount of 2030 Senior Notes redeemed, plus a "make-whole" premium and accrued and unpaid interest, if any, to, but excluding, the applicable redemption date. At any time prior to October 15, 2027, BKV Upstream Midstream may redeem up to 40% of the aggregate principal amount of 2030 Senior Notes, with an amount of cash not greater than the net cash proceeds of one or more equity offerings, at a redemption price equal to 107.500% of the principal amount of the 2030 Senior Notes redeemed, plus accrued and unpaid interest, if any, to, but excluding, the applicable redemption date, as long as at least 60% of the aggregate principal amount of 2030 Senior Notes originally issued (excluding any 2030 Senior Notes held by BKV Upstream Midstream and its subsidiaries) remains outstanding immediately after the occurrence of such redemption, and the redemption occurs within 180 days after the date of the closing of such equity offering. On or after October 15, 2027, BKV Upstream Midstream may, on any one or more occasions, redeem all or part of the 2030 Senior Notes at the redemption prices set forth below, plus accrued and unpaid interest, if any, to, but not including, the applicable redemption date, if redeemed during the 12-month period beginning on October 15 of the years indicated below:

| Year | Percentage |
|---|---|
| 2027 | 103.750 % |
| 2028 | 101.875 % |
| 2029 and thereafter | 100.000 % |

The indenture governing the 2030 Senior Notes contains covenants that limit the ability of BKV Upstream Midstream and its restricted subsidiaries to: (i) pay dividends on, purchase or redeem its capital stock or purchase or redeem certain subordinated debt; (ii) make certain investments; (iii) incur or guarantee additional indebtedness or issue certain types of preferred equity securities; (iv) create or incur certain secured debt; (v) sell assets; (vi) consolidate, merge or transfer all or substantially all of its assets; (vii) enter into agreements that restrict distributions or other payments from its restricted subsidiaries to BKV Upstream Midstream; (viii) engage in transactions with affiliates; and (ix) create or designate unrestricted subsidiaries.

The indenture governing the 2030 Senior Notes also contains customary events of default, including (i) default for 30 days in payment when due and payable of interest on the 2030 Senior Notes; (ii) default in payment when due and payable of the principal of, or premium, if any, on, the 2030 Senior Notes; (iii) cross-defaults to certain indebtedness; and (iv) certain events of bankruptcy or insolvency with respect to BKV Upstream Midstream or certain of its restricted subsidiaries. If an event of default arises from certain events of bankruptcy, insolvency or reorganization, with respect to BKV Upstream Midstream or certain of its restricted subsidiaries, all outstanding 2030 Senior Notes will become due and payable without further action or notice. If an event of default occurs and is continuing, the trustee or the holders of at least 25% in aggregate principal amount of the then outstanding 2030 Senior Notes may declare all the 2030 Senior Notes to be due and payable immediately.

If BKV Upstream Midstream experiences certain types of changes of control and the rating of the 2030 Senior Notes is reduced as a result thereof within 60 days, holders of the 2030 Senior Notes will be entitled to require BKV Upstream Midstream to repurchase the 2030 Senior Notes at 101% of the principal amount thereof, pursuant to an offer on the terms set forth in the indenture governing the 2030 Senior Notes.

***RBL Credit Agreement***

On June 11, 2024, BKV Corporation, as a 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, 2025, the RBL Credit Agreement had a borrowing base of $1.0 billion, an elected commitment of $800.0 million, and the ability to issue up to $40.0 million in letters of credit. As of March 6, 2026, 110.0 million of revolving borrowings and $15.0 million of letters of credit were outstanding under the RBL Credit Agreement, leaving $675.0 million of available capacity thereunder for future borrowings and letters of credit.

The loans under the RBL Credit Agreement 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 senior secured basis by 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 an

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. 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. For the years ended December 31, 2025 and 2024, BKV Upstream Midstream recognized $2.5 million and $0.8 million, respectively, of commitment fees, which are 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 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.

The RBL Credit Agreement requires BKV Upstream Midstream and its restricted subsidiaries to always hedge not less than 50% of reasonably anticipated projected production from their proved developed producing reserves for the subsequent 24 calendar month period immediately following the date financial statements are required to be delivered under the RBL Credit Agreement for each fiscal quarter.

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 (subject to certain limitations in the RBL Credit Agreement). As of December 31, 2025, BKV Upstream Midstream was in compliance with such covenants in 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.

Financing costs related to the RBL Credit Agreement are deferred and capitalized as debt issuance costs and are included within other assets on the consolidated balance sheets. During the years ended December 31, 2025 and 2024, BKV paid debt issuance costs of $2.3 million and $8.1 million, respectively, which are amortized to interest expense on the Company's consolidated statements of operations over the term of the RBL credit agreement. As of December 31, 2025 and 2024, $6.9 million of unamortized debt issuance costs remained outstanding for both periods. As of December 31, 2025, the RBL Credit Agreement had a zero balance and the outstanding letters of credit were $15.0 million. As of December 31, 2024, the effective interest rate on the RBL Credit Agreement was 7.50%, and the outstanding letters of credit were $14.1 million.

***Subordinated Intercompany Loan Agreement***

On June 18, 2024, the Company paid down $25.0 million of the $75.0 million outstanding on the related party loan with BNAC, including interest, and on September 30, 2024, the Company repaid the outstanding balance of $50.0 million, including interest, with proceeds from the IPO.

***BKV-BPP Power Loan Agreements and Credit Facilities***

*Temple I Loan Agreements*

On October 14, 2021, BKV-BPP Power entered into a Loan Agreement (the "$141 Million Banpu Loan Agreement") with BNAC, which allowed for a single drawdown in the amount of $141.0 million. On November 1, 2021, BKV-BPP Power borrowed $141.0 million under the $141 Million Banpu Loan Agreement for the purpose of acquiring Temple I and working capital.

On October 15, 2021, BKV-BPP Power entered into a Loan Agreement (the "$141 Million BPPUS Loan Agreement" and, together with the $141 Million Banpu Loan Agreement, the "Temple I Loan Agreements") with BPPUS, which allowed for a single drawdown in the amount of $141.0 million. On November 21, 2021, BKV-BPP Power borrowed $141.0 million under the $141 Million BPPUS Loan Agreement (and in addition to the $141.0 million borrowed under the $141 Million Banpu Loan Agreement) for the purpose of acquiring Temple I and working capital.

BKV-BPP Power's payment obligations under the Temple I Loan Agreements are senior unsecured indebtedness. The Temple I Loan Agreements bear interest at 6-month SOFR plus 5.25% per annum. Interest on the loans is payable on a semi-annual basis, and the loans will mature on November 1, 2026. BKV-BPP Power is permitted to prepay the loans at any time, with no prepayment premium. The Temple I Loan Agreements include covenants that, among other things, prohibit BKV-BPP Power from merging, incurring liens or incurring any additional indebtedness or guarantees. The Temple I Loan Agreements include financial covenants that require BKV-BPP Power to maintain a minimum net worth (as defined in the Temple I Loan Agreements, but generally meaning total assets minus total liabilities). In the $141 Million Banpu Loan Agreement, the minimum net worth requirement is $120.0 million and in the $141 Million BPPUS Loan Agreement, the minimum net worth requirement is $40.0 million. Under the Temple I Loan Agreements, BNAC and BPPUS have no recourse to BKV Corporation with respect to any amounts owed to them thereunder and BKV Corporation is not liable in any manner (and is not required to provide security) for any obligations owed to BNAC or BPPUS thereunder. As of December 31, 2025 and 2024, the outstanding principal balance of the Temple I Loan Agreements for each affiliate was $95.5 million and $105.0 million, respectively.

*Temple Credit Facilities*

On July 10, 2023, Temple Generation Intermediate Holdings II, LLC ("Temple Intermediate II"), an indirect subsidiary of BKV-BPP Power, as borrower, Temple Generation I, LLC ("Temple Generation I"), Temple Generation II, LLC (previously, CXA Temple 2, LLC) ("Temple Generation II"), each of Temple Generation I and Temple Generation II being a subsidiary of Temple Intermediate II, and Temple Generation SF LLC ("Temple Generation SF"), a joint subsidiary of Temple Generation I and Temple Generation II, each as subsidiary guarantors, entered into a credit agreement (the "Beal Credit Agreement") with Beal Bank USA and the other lenders from time to time party thereto that provides the following credit facilities (collectively, the "Temple Credit Facilities"): (i) a senior secured term loan facility with an aggregate principal amount of $500.0 million (the "Temple Term Loan Facility"), which was fully drawn in an amount equal to $500.0 million on the closing date, and (ii) a senior secured revolving credit facility in the aggregate principal amount not to exceed $60.0 million (the "Temple Revolving Facility"), which was fully drawn in an amount equal to $60.0 million on the closing date. The interest is payable annually for the Temple Credit Facilities at a rate equal to SOFR plus an interest rate margin of 4.60%.

The Temple Term Loan Facility requires a quarterly repayment at a minimum of $2.5 million per quarter, beginning on September 30, 2023. The final aggregate principal installment for the Temple Term Loan Facility is due and payable on July 10, 2028 (subject to extension by up to two additional one-year periods), and the Temple Revolving Facility terminates five business days prior to the Temple Term Loan Facility maturity date. On the closing date, Temple Intermediate II applied the proceeds of the Temple Term Loan Facility to fund a portion of the Temple II acquisition and applied the proceeds of the Temple Revolving Facility for general corporate purposes, including working capital and operating expenses. Any prepayment of the Temple Term Loan Facility prior to the third anniversary of the closing date thereof is subject to a prepayment penalty. Amounts repaid by Temple Intermediate II with respect to the Temple Term Loan Facility may not be reborrowed. Amounts repaid by Temple Intermediate II with respect to the Temple Revolving Facility may be reborrowed upon satisfaction of customary conditions.

The obligations under the Temple Credit Facilities are secured by (i) all of the assets of Temple Intermediate II, Temple Generation I, Temple Generation II and Temple Generation SF, including the Temple Plants and all other personal property and real property of such entities and (ii) 100.0% of the equity interests in each of Temple Generation I, Temple Generation II, Temple Generation SF, and Temple Intermediate II. This collateral will remain pledged to Beal Bank until all secured obligations under the Temple Credit Facilities have been satisfied in full. Upon the occurrence and continuation of an event of default under either of the

Temple Credit Facilities, Beal Bank has customary secured creditor remedies, including the right to foreclose upon the pledged collateral. As of December 31, 2025 and 2024, the weighted average effective interest rate on the outstanding balances under the RBL Credit Agreement, the Temple I Loan Agreements, and the Temple Credit Facilities was 8.86% and 8.79%, respectively.

**Note 5 - Natural Gas Properties & Other Property, Plant, and Equipment**

As of December 31, 2025 and 2024, accumulated depreciation, depletion, and amortization for developed natural gas properties was $825.7 million and $697.0 million, respectively. Depreciation, depletion, and amortization expense for developed natural gas properties was $128.7 million, $188.7 million, and $196.1 million for the years ended December 31, 2025, 2024, and 2023 respectively.

Midstream assets consisted of the following:

| | December 31, | |
|---|---|---|
| **(in thousands)** | **2025** | **2024** |
| Compressor station | $ 33,752 | $ 33,461 |
| Meter station | 67 | 67 |
| Pipelines | 244,155 | 243,116 |
| Total | 277,974 | 276,644 |
| Accumulated depreciation | (23,770) | (17,285) |
| Midstream assets, net | $ 254,204 | $ 259,359 |

Depreciation expense on midstream assets was $6.4 million, $6.9 million, and $7.5 million for the years ended December 31, 2025, 2024, and 2023, respectively.

Other property, plant, and equipment consisted of the following:

| | December 31, | |
|---|---|---|
| **(in thousands)** | **2025** | **2024** |
| Plant facility | $ 926,092 | $ 924,779 |
| Carbon capture, utilization, and sequestration | 114,261 | 69,743 |
| Buildings | 6,746 | 15,707 |
| Furniture, fixtures, equipment, and vehicles | 27,643 | 24,540 |
| Computer software | 8,461 | 5,595 |
| Leasehold improvements | 1,685 | 1,685 |
| Land | 8,090 | 4,589 |
| Construction in process | 6,350 | 3,575 |
| Total | 1,099,328 | 1,050,213 |
| Accumulated depreciation | (154,916) | (113,416) |
| Other property, plant, and equipment, net | $ 944,412 | $ 936,797 |

Depreciation expense for other property, plant, and equipment was $43.3 million, $43.7 million, and $37.1 million for the years ended December 31, 2025, 2024, and 2023, respectively. During the year ended December 31, 2025, the Company received proceeds on the sale of other properties and equipment of $6.9 million, which included the sale of the Bridgeport field office of $5.5 million, less transaction costs of $0.4 million, and recognized a loss on sale of these properties and equipment of $1.8 million, which is included in the gains (losses) on sales of assets, net in the consolidated statements of operations. 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 (losses) on sales of assets, net 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 (losses) on sales of assets, net, in the consolidated statements of operations.

*Write-Off of ERP System*

During the year ended December 31, 2025, the Company was actively implementing a new enterprise resource planning (“ERP”) system and had capitalized $6.9 million in software costs. However, during the third quarter of 2025, the Company decided to discontinue implementation of this ERP system and wrote off $5.6 million of capitalized software costs, which is included in other operating expense in the consolidated statements of operations, as the system was determined to no longer align with the Company's operational and strategic needs. The Company is in the process of implementing a new ERP system that better supports its business processes and long-term objectives.

*Intangible Assets*

The Company's intangible assets, reflected within other noncurrent assets on the consolidated balance sheets, represent customer listings, which are amortized using the straight-line method based on its estimated useful life of 3 years. The customer listings were acquired in 2023 for $1.8 million, and amortization on these listings was $0.6 million for both the years ended December 31, 2025 and 2024, and $0.3 million for the year ended December 31, 2023. As of December 31, 2025, the estimated future aggregate amortization expense for intangible assets is expected to be $0.3 million in 2026.

**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, fixed-price power sales, and fixed price power purchases are based on measurements derived indirectly from observable inputs or from quoted prices from markets that are less liquid, they are classified as Level 2 within the fair value hierarchy. The heat rate call options are classified as Level 3 within the fair value hierarchy because their valuation relies on significant unobservable inputs. These inputs include correlation between the underlying power and natural gas commodities and volatility assumptions for non-liquid delivery periods, which require management judgment and are not directly observable in the market.

The Company factors its own non-performance risk into the valuation of derivatives using current published credit default swap rates. As of December 31, 2025 and 2024, the impact of the non-performance risk adjustment to the Company's fair value of commodity derivative liabilities was $1.6 million and $6.6 million, respectively.

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, 2025 | | |
|---|---|---|---|
| | Fair Value Measurements Using: | | |
| (in thousands) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Total |
| Financial assets | | | |
| Derivative instruments | | | |
| Natural gas derivatives | $ 57,135 | $ — | $ 57,135 |
| NGL derivatives | 13,807 | — | 13,807 |
| Natural gas basis swaps | 17,272 | — | 17,272 |
| Power derivatives | 1,347 | 771 | 2,118 |
| Financial liabilities | | | |
| Derivative instruments | | | |
| Natural gas derivatives | 6,572 | — | 6,572 |
| NGL derivatives | 407 | — | 407 |
| Natural gas basis swaps | 1,328 | — | 1,328 |
| Power derivatives | 3,514 | 2,415 | 5,929 |

| (in thousands) | December 31, 2024 Fair Value Measurements Using: Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Total |
|---|---|---|---|
| Financial assets | | | |
| Derivative instruments | | | |
| Natural gas derivatives | $ 6,094 | $ — | $ 6,094 |
| Power derivatives | 2,790 | — | 2,790 |
| Financial liabilities | | | |
| Derivative instruments | | | |
| Natural gas derivatives | 54,083 | — | 54,083 |
| NGL derivatives | 8,973 | — | 8,973 |
| Natural gas basis swaps | 5,380 | — | 5,380 |
| Power derivatives | 15,648 | 3,595 | 19,243 |

The contingent consideration was generated from the Devon Barnett Acquisition and on January 8, 2025, the Company paid the final 2024 contingent consideration of $20.0 million, which is reflected as contingent consideration payable within current liabilities on the consolidated balance sheets as of December 31, 2024. 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 from the 2021 Plan (as defined in *Note 13 - Stockholders' Equity and Mezzanine Equity*) were recorded at fair value upon initial recognition in mezzanine equity, and its common stock was valued using both observable (Level 2) and unobservable (Level 3) inputs. Subsequent to the Company's IPO, the minority ownership puttable shares were converted to common stock. The minority ownership puttable shares are further described in *Note 13 - Stockholders' Equity and Mezzanine Equity*.

Equity-based compensation from the 2021 Plan was 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, determined using the same valuation methodologies applied to the minority ownership puttable shares. Equity-based compensation is further described in *Note 13 - Stockholders' Equity and Mezzanine Equity*.

The tables below set forth the changes in the Company's Level 3 fair value measurements (in thousands):

| Derivatives | Year Ended December 31, 2025 |
|---|---|
| Balance, beginning of period | $ (3,595) |
| Derivative settlements | (62,258) |
| Derivative realized gains (losses) | 62,258 |
| Derivative unrealized gains (losses) | 1,951 |
| Balance, end of period | $ (1,644) |

| | Year Ended December 31, 2024 Contingent Consideration | Minority Ownership | Equity-Based Compensation | Derivatives | Total |
|---|---|---|---|---|---|
| Balance, beginning of period | $ 29,676 | $ 59,988 | $ 126,966 | $ (42,091) | $ 174,539 |
| 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) |
| Derivative settlements | — | — | — | (88,637) | (88,637) |
| Derivative realized gains (losses) | — | — | — | 88,637 | 88,637 |
| Change in fair market value (all instruments) | (9,676) | (16,989) | (9,310) | 38,496 | 2,521 |
| Balance, end of period | $ — | $ — | $ — | $ (3,595) | $ (3,595) |

| | Year Ended December 31, 2023 | | | | |
|---|---|---|---|---|---|
| | Contingent Consideration | Minority Ownership | Equity-Based Compensation | Derivatives | Total |
| Balance, beginning of period | $ 88,051 | $ 62,712 | $ 89,171 | $ (1,994) | $ 237,940 |
| Contingent consideration - settled | (20,000) | — | — | — | (20,000) |
| Grant date fair value of equity-based compensation, pre-IPO | — | (2) | 22,193 | — | 22,191 |
| Derivative settlements | — | — | — | (55,258) | (55,258) |
| Derivative realized gains (losses) | — | — | — | 55,258 | 55,258 |
| Change in fair market value (all instruments) | (38,375) | (2,722) | 15,602 | (40,097) | (65,592) |
| Balance, end of period | $ 29,676 | $ 59,988 | $ 126,966 | $ (42,091) | $ 174,539 |

The following table is the quantitative information regarding significant unobservable inputs used in the measurement of Level 3 positions:

| December 31, 2025 | | | | | |
|---|---|---|---|---|---|
| Valuation Technique | Significant Unobservable Input | Range | | Weighted Average | Description |
| Kirk Spread Option Model | Power and natural gas price correlation | 92.7 % | | 92.7 % | Estimated correlation between underlying commodities |
| Kirk Spread Option Model | Power volatility (non-liquid hours) | 42.9 % | 52.4 % | 47.7 % | Extrapolated from observable 5x16 implied volatilities and shaped for delivery periods (2x16 and 7x8) |

| December 31, 2024 | | | | | |
|---|---|---|---|---|---|
| Valuation Technique | Significant Unobservable Input | Range | | Weighted Average | Description |
| Kirk Spread Option Model | Power and natural gas price correlation | 70.4 % | | 70.4 % | Estimated correlation between underlying commodities |
| Kirk Spread Option Model | Power volatility (non-liquid hours) | 56.8 % | 69.4 % | 63.1 % | Extrapolated from observable 5x16 implied volatilities and shaped for delivery periods (2x16 and 7x8) |

***Other Fair Value Measurements***

The carrying value of cash and cash equivalents, restricted cash, accounts receivable, net, and accounts payable and accrued liabilities approximate their fair values due to the short-term maturities of these instruments. Long-term debt obligations under the RBL Credit Agreement, the Temple I Loan Agreements, and the Temple Credit Facilities also approximate fair value because the variable rates of interest are market-based. The fair value of the 2030 Senior Notes as of December 31, 2025, was approximately $507.5 million based on quoted market prices from banks and are classified Level 2 in the fair value hierarchy. The 2030 Senior Notes are carried on the consolidated balance sheets at their original issuance value, as adjusted over time to accrete that value to par.

**Note 7 - Derivative Instruments**

The Company may utilize derivative contracts in connection with its natural gas, NGL, and power operations to provide an economic hedge of the Company’s exposure to commodity price risk associated with anticipated future natural gas and NGL production, as well as to manage the Company’s exposure to delivery risk, optimize physical and contractual assets in the Company’s portfolio, and manage working capital requirements. 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 - *Derivatives and Hedging*, and the fair value of the contingent consideration was $20.0 million as of December 31, 2024, and is included in contingent consideration payable in the consolidated balance sheets. The change in the fair value of this contingent consideration was a gain of $7.5 million and $25.0 million for the years ended December 31, 2024 and 2023, 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, 2025 consisted of commodity swaps, basis swaps, put and call options, producer collar agreements, fixed-price natural gas forwards, fixed-price power forwards, and HRCOs, 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, 2025 | | |
|---|---|---|---|---|
| (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 | $ 66,787 | $ (2,887) | $ 63,900 |
| Noncurrent derivative assets | Commodity derivative assets | 34,116 | (7,684) | 26,432 |
| Current derivative liabilities | Commodity derivative liabilities, current | 11,356 | (2,887) | 8,469 |
| Noncurrent derivative liabilities | Commodity derivative liabilities | 13,451 | (7,684) | 5,767 |

| | | 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 | $ 14,071 | $ (5,187) | $ 8,884 |
| Noncurrent derivative assets | Commodity derivative assets | 872 | (872) | — |
| Current derivative liabilities | Commodity derivative liabilities, current | 45,280 | (5,187) | 40,093 |
| Noncurrent derivative liabilities | Commodity derivative liabilities | 48,458 | (872) | 47,586 |

***Derivative Contracts***

*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.

*Fixed-Price Power Forwards and HRCOs*

For the power generated out of the Temple Plants, the Company enters into fixed-price power sales contracts in which energy is delivered to the ERCOT north hub at a fixed-price per MWh. The contracts contain an agreed upon quantity of total MW and total MWh. The Company also enters into fixed-price power purchase contracts to hedge BKV-BPP Retail power purchases for its retail customers.

The Company also enters into bilateral heat rate call option (“HRCO”) agreements under which counterparties obtain the right to receive specified quantities of power at the Temple Plants, subject to the contractual terms of each agreement. As of December 31, 2025, the Company had four outstanding HRCO contracts with two counterparties, representing contracted capacity of 600 MW, which became effective January 1, 2026. As of December 31, 2024, the Company had two outstanding HRCO contracts with two counterparties, representing contracted capacity of 200 MW, which became effective January 1, 2025. Under the agreements, the Company receives fixed monthly capacity premiums from the counterparties. If exercised, the counterparties receive specified quantities of power from the Temple Plants with settlement based on contractually specified prices that incorporate the applicable heat rate, natural gas index pricing, and other contractual charges. Premiums received under the Company’s HRCO agreements are recognized within derivative gains, net as realized gains (losses), net on the consolidated statements of operations. Fuel costs incurred to satisfy exercised HRCO obligations are recognized within fuel commodity costs on the consolidated statements of operations. Outstanding HRCO agreements are remeasured at fair value, with changes in fair value recognized within derivative gains, net as unrealized gains (losses), net on the consolidated statements of operations.

The following tables set forth the derivative gains, net on the consolidated statements of operations:

| (in thousands) | Income Statement Location | Year Ended December 31, 2025 | 2024 | 2023 |
|---|---|---|---|---|
| Realized gains (losses) on derivatives (natural gas) | Derivative gains, net | $ (8,808) | $ 76,670 | $ 86,131 |
| Realized gains (losses) on derivatives (NGL) | Derivative gains, net | (1,639) | 3,994 | (2,643) |
| Realized gains on derivatives (power sales) | Derivative gains, net | 269,958 | 207,729 | 132,843 |
| Realized losses on derivatives (purchased power) | Purchased power | (41,226) | (51,764) | (10,620) |
| Total realized gains on derivatives, net | | $ 218,285 | $ 236,629 | $ 205,711 |

| (in thousands) | Income Statement Location | Year Ended December 31, 2025 | 2024 | 2023 |
|---|---|---|---|---|
| Unrealized gains (losses) on derivatives (natural gas) | Derivative gains, net | $ 80,242 | $ (101,325) | $ 111,315 |
| Unrealized gains (losses) on derivatives (NGL) | Derivative gains, net | 25,089 | (18,856) | 16,906 |
| Unrealized gains (losses) on derivatives (power sales) | Derivative gains, net | 15,027 | 39,248 | (53,828) |
| Unrealized gains (losses) on derivatives (purchased power) | Purchased power | (2,384) | (1,684) | 554 |
| Total unrealized gains (losses) on derivatives, net | | $ 117,974 | $ (82,617) | $ 74,947 |

There were no early-terminated natural gas commodity derivative swap contracts during the year ended December 31, 2025. Realized gains (losses) on derivatives (natural gas) 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. Realized gains (losses) on derivatives (natural gas) 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.

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 of $5.00 per MMBtu. 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. During the fourth quarter of 2025, the Company terminated a portion of the call option contracts scheduled to settle in 2026 in exchange for natural gas fixed-price swap contracts that will settle in 2026. No realized gain or loss was recognized on this transaction.

During the first quarter in 2025, the Company entered into agreements to buy put options and subsequently paid a net premium of $16.2 million for contracts that settle in 2026 and 2027. The put 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. The premium paid was recorded as an asset and is subsequently adjusted to the current fair value of the option written. During the fourth quarter of 2025, the Company terminated a portion of the put option contracts scheduled to settle in 2026 in exchange for natural gas fixed-price swap contracts that will settle in 2026. No realized gain or loss was recognized on this transaction.

***Derivative Contract Volumes and Fair Values***

The following tables summarize the Company’s outstanding derivative positions as of December 31, 2025 by commodity and contract type, including volume, pricing indices, or reference points, and associated fair values.

The following table summarizes the Company's power derivatives:

| Instrument | Units | Quantity | Pricing Index | Fair Value as of December 31, 2025 (in thousands) |
|---|---|---|---|---|
| 2026 | | | | |
| Swap | MMBtu | 6,132,000 | HSC Gas Daily | $ (2,540) |
| Power forwards - sales | MWh | 876,000 | ERCOT North | $ 1,347 |
| Heat rate call option | MMBtu | 5,256,000 | Various | $ (1,644) |
| Power forwards - purchases | MWh | (453,195) | Various | $ (3,514) |

The following table summarizes the Company's 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, 2025 (in thousands) |
|---|---|---|---|---|---|
| 2026 | | | | | |
| Swap | 154,460,650 | $ 3.86 | | | $ 35,268 |
| 2027 | | | | | |
| Swap | 79,825,383 | $ 4.03 | | | $ 11,938 |
| Collars | 37,662,319 | | $ 3.57 | $ 4.00 | $ (3,225) |
| Call options | 36,500,000 | | | $ 5.00 | $ (9,372) |
| Put options | 36,500,000 | | $ 3.00 | | $ 7,014 |
| 2028 | | | | | |
| Swap | 51,995,323 | $ 3.93 | | | $ 11,480 |

The following table summarizes the Company's natural gas basis derivatives by reference price:

| Instrument | Basis Reference Price | MMBtu | Weighted Average Basis Differential | Fair Value as of December 31, 2025 (in thousands) |
|---|---|---|---|---|
| 2026 | | | | |
| Swap | Transco Leidy Basis | 43,800,000 | $ (0.80) | $ 238 |
| Swap | HSC Basis | 54,750,000 | $ (0.32) | $ 7,408 |
| Swap | Transco St 85 (Z4) Basis | 36,500,000 | $ 0.62 | $ 4,225 |
| Swap | NGPL TXOK Basis | 47,521,249 | $ (0.36) | $ 3,384 |
| 2027 | | | | |
| Swap | Transco Leidy Basis | 7,300,000 | $ (0.77) | $ 36 |
| Swap | HSC Basis | 7,300,000 | $ (0.25) | $ 458 |
| Swap | NGPL TXOK Basis | 16,965,270 | $ (0.31) | $ (93) |
| 2028 | | | | |
| Swap | HSC Basis | 10,980,000 | $ (0.17) | $ 289 |

The following table summarizes the Company's natural gas liquids derivatives position by product and reference price:

| Instrument | Commodity Reference Price | Gallons | Weighted Average Price (USD) | Fair Value as of December 31, 2025 (in thousands) |
|---|---|---|---|---|
| 2026 | | | | |
| Swap | OPIS Purity Ethane Mont Belvieu | 142,691,481 | $ 0.25 | $ 468 |
| Swap | OPIS IsoButane Mont Belvieu Non-TET | 10,075,218 | $ 0.83 | $ 185 |
| Swap | OPIS Normal Butane Mont Belvieu Non-TET | 16,928,342 | $ 0.80 | $ 836 |
| Swap | OPIS Propane Mont Belvieu Non-TET | 59,163,120 | $ 0.69 | $ 4,359 |
| Swap | OPIS Natural Gasoline Mont Belvieu Non-TET | 25,835,930 | $ 1.37 | $ 5,411 |
| 2027 | | | | |
| Swap | OPIS Purity Ethane Mont Belvieu | 79,965,970 | $ 0.28 | $ 935 |
| Swap | OPIS IsoButane Mont Belvieu Non-TET | 2,732,077 | $ 0.76 | $ 21 |
| Swap | OPIS Normal Butane Mont Belvieu Non-TET | 4,873,274 | $ 0.74 | $ 92 |
| Swap | OPIS Propane Mont Belvieu Non-TET | 15,478,884 | $ 0.64 | $ 309 |
| Swap | OPIS Natural Gasoline Mont Belvieu Non-TET | 6,777,531 | $ 1.26 | $ 783 |

**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, 2025 and 2024, the liability has been accreted to its present value and, for the years ended December 31, 2025, 2024, and 2023, accretion expense of $15.1 million, $14.1 million, and $13.2 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:

| (in thousands) | Year Ended December 31, 2025 | 2024 | 2023 |
|---|---|---|---|
| Balance, as of January 1, | $ 201,158 | $ 195,476 | $ 182,300 |
| Additions through acquisitions [1] | 18,761 | — | 640 |
| Liabilities incurred | 226 | 42 | 89 |
| Liabilities settled | (1,873) | (1,288) | (759) |
| Liabilities associated with property sold [2] | — | (7,133) | — |
| Accretion of discount | 15,067 | 14,061 | 13,206 |
| Balance, as of December 31, | 233,339 | 201,158 | 195,476 |
| Less current portion | (2,967) | (2,363) | (2,271) |
| Asset retirement obligations, long-term | $ 230,372 | $ 198,795 | $ 193,205 |

(1) Relates to the Bedrock Acquisition. See *Note 3 - Acquisition and Dispositions* for further discussion.

(2) 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 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. For the years ended December 31, 2024 and 2023, interest expense recognized on this loan agreement was $5.2 million and $7.1 million, respectively.

Prior to the consummation of the IPO, the Company filed its income tax returns as part of BNAC. Accordingly, Section 45Q tax credits generated by the Barnett Net Zero Project were recognized by BNAC but attributable to the Company. 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, and as of December 31, 2025 and 2024, the Company had receivables of $10.8 million and $14.7 million, respectively, from BNAC related to those Section 45Q tax credits, which is included in accounts receivable, related parties on the consolidated balance sheets. Separately, as of December 31, 2025 and 2024, the Company had payables of $0.8 million and $1.4 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, 2025 and 2024, the Company had a receivable from BNAC of $0.4 million and $0.2 million, respectively, related to shared general and administrative expenses, which is included in accounts receivable, related parties on the consolidated balance sheets.

On October 14, 2021 and October 21, 2025, BKV-BPP Power LLC entered into the $141 Million Banpu Loan Agreement and the Temple I Loan Agreements as borrower to lenders, BPPUS and BNAC. Refer to *Note 4 - Debt* for further details of this agreement.

**Note 10 - Revenue from Contracts with Customers**

All of the Company’s revenues from contracts with customers are generated in the states of Pennsylvania and Texas. Revenues from contracts with customers consist of the following:

| | Year Ended December 31, 2025 | | |
|---|---|---|---|
| **(in thousands)** | **Pennsylvania** | **Texas** | **Total** |
| Natural gas | $ 67,668 | $ 607,410 | $ 675,078 |
| NGLs | — | 173,059 | 173,059 |
| Oil | — | 9,460 | 9,460 |
| Total natural gas, NGL, and oil sales | 67,668 | 789,929 | 857,597 |
| | | | |
| Merchant energy sales and other | — | 288,981 | 288,981 |
| Energy retail sales | — | 154,654 | 154,654 |
| Solar revenue | — | 398 | 398 |
| Physical power purchased | — | (195,281) | (195,281) |
| Revenue from contracts with customers - power | — | 248,752 | 248,752 |
| | | | |
| Marketing revenues | — | 12,304 | 12,304 |
| Midstream revenues | — | 10,456 | 10,456 |
| Other | — | 11,664 | 11,664 |
| Total | $ 67,668 | $ 1,073,105 | $ 1,140,773 |

| | 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 |
| | | | |
| Merchant energy sales and other | — | 234,477 | 234,477 |
| Energy retail sales | — | 135,652 | 135,652 |
| Solar revenue | — | 128 | 128 |
| Physical power purchased | — | (151,989) | (151,989) |
| Revenue from contracts with customers - power | — | 218,268 | 218,268 |
| | | | |
| Marketing revenues | $ — | 10,668 | 10,668 |
| Midstream revenues | 2,014 | 10,546 | 12,560 |
| Other | — | 6,631 | 6,631 |
| Total | $ 40,809 | $ 764,888 | $ 805,697 |

| (in thousands) | Year Ended December 31, 2023 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 |
| | | | |
| Merchant energy sales and other | — | 413,915 | 413,915 |
| Energy retail sales | — | 40,261 | 40,261 |
| Physical power purchased | — | (179,553) | (179,553) |
| Revenue from contracts with customers - power | — | 274,623 | 274,623 |
| | | | |
| Marketing revenues | — | 8,710 | 8,710 |
| Midstream revenues | 4,635 | 11,533 | 16,168 |
| Other | — | 3,957 | 3,957 |
| Total | $ 62,313 | $ 947,296 | $ 1,009,609 |

***Accounts Receivable and Revenue from Contracts with Customers***

Substantially all of the Company’s accounts receivable, net result from the sale of natural gas, joint interest billings, and power sales. The Company sells the substantial majority of its 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. The Company sells power to retail and wholesale customers on the ERCOT power grid. As of December 31, 2025 and 2024, the Company’s accounts receivable, net consisted of the following:

| (in thousands) | December 31, 2025 | 2024 |
|---|---|---|
| Accounts receivable - contracts with customers | $ 97,308 | $ 61,960 |
| Accounts receivable - derivative instruments | 11,383 | 8,663 |
| Accounts receivable - other | 21,656 | 3,568 |
| Allowance for credit losses | (1,270) | (2,511) |
| Total accounts receivable, net | $ 129,077 | $ 71,680 |

**Note 11 - Accounts Payable and Accrued Liabilities**

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

| (in thousands) | December 31, 2025 | 2024 |
|---|---|---|
| Accounts payable | $ 100,432 | $ 75,150 |
| Revenues payable | 36,310 | 17,921 |
| Accrued payroll | 31,069 | 25,049 |
| Oil and gas production and other taxes payable | 21,604 | 21,263 |
| Commodity derivative settlements payable | 24,705 | 3,891 |
| Other accrued liabilities | 15,367 | 19,250 |
| Total | $ 229,487 | $ 162,524 |

**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 and in December 2025, the Company’s board of directors approved an amendment and restatement of the 2024 Plan to increase the number of shares of common stock available for grant and issuance under the 2024 Plan by 2,500,000 shares, effective March 5, 2026 (the 2024 Plan, as so amended and restated, the “A&R 2024 Plan”). The A&R 2024 Plan was also approved by holders of a majority of the voting power of the Company’s outstanding capital stock in January 2026.

The A&R 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 A&R 2024 Plan, the Company can issue up to 7,500,000 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 A&R 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 A&R 2024 Plan. Each grant of an award under the A&R 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 A&R 2024 Plan), which outlines the number of shares of common stock, earning or vesting terms, and any other terms consistent with the A&R 2024 Plan.

Any shares of common stock awarded under the A&R 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 A&R 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, 2025, 2,685,601 shares were available for future grants under the 2024 Plan. As of March 5, 2026, 4,713,922 shares were available for future grants under the A&R 2024 Plan.

*Performance-Based Restricted Stock Units*

On September 27, 2024, the Company granted 704,649 PRSUs under the 2024 Plan that cliff vest on December 31, 2026, and are subject to a performance period beginning January 1, 2024 and ending on December 31, 2026. During the year ended December 31, 2025, the Company granted 670,181 PRSUs, which cliff vest on December 31, 2027, and are subject to a performance period beginning January 1, 2025 and ending on December 31, 2027, (collectively with the PRSU grants issued in 2024, the "PRSU Performance Period"). The table below summarizes the PRSU activity for the year ended December 31, 2025:

| **(in thousands, except per share amounts)** | **Shares** | **Weighted Average Grant Date Fair Value** |
|---|---|---|
| Unvested PRSUs as of January 1, 2025 | 703 | $ 12.23 |
| Granted | 670 | $ 19.44 |
| Vested | (52) | $ 12.92 |
| Forfeitures | (136) | $ 14.14 |
| Unvested PRSUs as of December 31, 2025 | 1,185 | $ 16.06 |

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 PRSU Performance Period, weighted at 30%, (ii) relative Total Shareholder Return ("rTSR") of the common stock of the Company's benchmark group during the PRSU Performance Period, weighted at 30%, and (iii) Return on Capital Employed ("ROCE") based on the average annual performance over the 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. 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, 2025, management estimates ROCE performance for the post IPO grants issued during the year ended December 31, 2024 to be lower than the target performance by approximately 2.1%, and for the grants that were issued during the year ended December 31, 2025 to be higher than the target performance level by approximately 55.4%. The grant date fair value of the PRSUs presented in the activity for the years ended December 31, 2025 and 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 fair value was estimated using the following assumptions for the PRSUs granted for the years ended December 31, 2025 and 2024:

| | Year Ended December 31, | |
|---|---|---|
| | 2025 (1) | 2024 |
| Volatility (2) | 40 % | 40 % |
| Expected dividend rate | — % | — % |
| Risk free rate | 3.9 % | 3.5 % |
| aTSR weighted average grant date value | $ 14.39 | $ 6.78 |
| rTSR weighted average grant date value | $ 23.90 | $ 9.91 |
| ROCE | $ 19.89 | $ 18.05 |
| Expected term | 3 years | 3 years |

(1) There were four specific grant dates during the year ended December 31, 2025. Amounts shown represent weighted average.

(2) Volatility uses a combination of daily historical and implied volatility over a look back period commensurate with the remaining term of the assets.

As of December 31, 2025, there was $14.6 million of unrecognized compensation expense related to the PRSU awards, which will be amortized over a weighted average period of 1.5 years.

Equity-based compensation related to PRSUs was $8.1 million and $0.8 million for the years ended December 31, 2025 and 2024, respectively, which is included in general and administrative expenses in the consolidated statements of operations.

*Time-Based Restricted Stock Units*

On September 27, 2024, the Company granted 469,835 TRSUs under the 2024 Plan, and during the year ended December 31, 2025, the Company granted 469,734 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, 2025:

| (in thousands, except per share amounts) | Shares | Weighted Average Grant Date Fair Value |
|---|---|---|
| Unvested TRSUs as of January 1, 2025 | 469 | $ 18.05 |
| Granted | 470 | $ 20.11 |
| Vested | (156) | $ 18.05 |
| Forfeited | (94) | $ 18.51 |
| Unvested TRSUs as of December 31, 2025 | 689 | $ 19.39 |

As of December 31, 2025, there was $8.7 million of unrecognized compensation expense related to the 2024 Plan TRSU awards, which will be amortized over a weighted average period of 1.7 years.

Equity-based compensation related to the TRSUs was $4.7 million and $2.8 million for the years ended December 31, 2025 and 2024, respectively, which is included in general and 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 are available for awards under the ESPP and eligible employees are only permitted 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, 2025, the Company recognized equity-based compensation expense related to the ESPP of $0.1 million, which is included in general and administrative expenses in the consolidated statements of operations.

***2021 Equity and Incentive Compensation Plan***

On January 1, 2021, the BKV Corporation Long-Term Incentive Plan (the "2021 Plan") was established. Upon consummation of the IPO, 7,724,499 RSUs were considered to have been granted under ASC 718 - *Compensation-Stock Compensation* ("ASC 718"), when taking into consideration PRSUs at the maximum performance level and TRSUs 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 statements of stockholders' equity and mezzanine equity, 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 (the "Performance Period"). As of December 31, 2023, or the Performance Period, the Company achieved its goals as follows: TSR met its threshold at 136%, ROCE met its threshold at 131%, and IPO readiness met its threshold at 200%. In February 2024, the Plan's committee approved the Company's goals and the PRSUs outstanding as of December 31, 2023, vested with some being forfeited prior to the Plan's approval. The following table summarizes the PRSU 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 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 years ended December 31, 2025 and 2024. For the year ended December 31, 2023, equity-based compensation related to the PRSUs was $22.2 million. This cost is 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 and 2023, equity-based compensation expense related to the TRSUs under the 2021 Plan was $12.7 million and $3.6 million, respectively, which is 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.

**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.

***Equity Offerings***

On December 3, 2025, the Company completed its public offering of 6,900,000 shares of common stock at a price to the public of $26.00 per share, for gross proceeds of $179.4 million. After underwriting discounts and commissions of $9.3 million, the Company received net proceeds from the offering of $170.1 million. The offering costs were recorded as a reduction to additional paid-in capital. BKV used the net proceeds from the offering, together with cash on hand, for the payment of the cash consideration of the purchase price in connection with BKV's acquisition of a controlling interest in BKV-BPP Power LLC and related expenses.

As part of the Bedrock Acquisition, the Company issued 5,233,957 shares of BKV's common stock to the Seller at a closing price of $23.74 at September 29, 2025. In accordance with the Bedrock Purchase Agreement, the number of shares issued was determined by dividing $110.0 million by $21.0166, the volume weighted average price of BKV common stock during the 20 consecutive trading-day period ending August 7, 2025. As of September 29, 2025 the date of the Bedrock Acquisition, the fair value of stock consideration was $124.3 million. Issuance costs related to the Bedrock Acquisition of $0.3 million were recorded as a reduction to additional paid-in capital. See Note 3 - Acquisition and Dispositions for further detail on the Bedrock Acquisition.

On September 27, 2024, the Company completed its 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.

On September 27, 2023, the Company made a capital call on BNAC of $150.0 million, and pursuant to the requirements of the existing stockholders' agreement, 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.

***Common Shares Issued and Outstanding***

As of December 31, 2025 and 2024, the Company had 96,871,868 and 84,600,301, 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, 2025, 2024, and 2023.

There were no cash dividends declared or paid during the years ended December 31, 2025, 2024, and 2023.

***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 and 2023, the Company recognized adjustments for the years ended December 31, 2024 and 2023, of $0.5 million, and $2.5 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 and 2023.

***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. 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, 2024 and 2023, the Company recognized an adjustment of an immaterial amount and $0.2 million, respectively, to the carrying value of the 2021 ESPP shares. 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 and 2023, the Company recognized an adjustment to the pro-rata portion of the RSUs which have vested in the amounts of $9.3 million and $15.6 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 and 2023, the Company issued 2,696,587 and 133,622 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, 2025, the Company did not purchase any shares. 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, and 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.

**Note 14 - Investments**

***Joint Ventures***

*BKV-BPP Power Joint Venture*

In 2021, the BKV-BPP Power Joint Venture was formed to own and operate combined-cycle natural gas-fired power generation facilities and a retail electricity marketing business in Temple, Texas. BKV-BPP Power generates revenues primarily through the sale of electricity and related products in the ERCOT market and through retail customer contracts, which allows the Company to integrate its upstream natural gas production with downstream power generation and marketing activities.

*BKV-CIP Joint Venture*

On May 8, 2025, BKV dCarbon Ventures, together with C Squared Solutions, Inc. (the "Class B Member"), a subsidiary of the Energy Transition Fund managed by Copenhagen Infrastructure Partners (CIP), and for the limited purposes specified therein, BKV Corporation, entered into the BKV-CIP JV Agreement forming BKV dCarbon Project, LLC (the "BKV-CIP Joint Venture") for the purpose of developing CCUS projects. On May 8, 2025, BKV dCarbon Ventures contributed to the BKV-CIP Joint Venture $40.3 million of CCUS assets that included the BKV dCarbon Barnett Zero, LLC and BKV dCarbon Las Tiendas, LLC and related assets (including the Barnett Zero and Eagle Ford CCUS projects), and $4.1 million of Section 45Q accrued receivables at carrying value, and committed to future contributions of certain CCUS projects, related assets, and/or cash in exchange for an interest in the BKV-CIP Joint Venture and 4,796,421 Class A Units at $10.00 per share. The Class B Member committed up to an initial $500.0 million in cash for use by the BKV-CIP Joint Venture in construction and operating new CCUS projects across the United States in exchange for no more than a 49% interest in the BKV-CIP Joint Venture. As of December 31, 2025 and during the year ended December 31, 2025, the Class B Member contributed $17.9 million, and received distributions of $1.2 million. In exchange for the Class B Member's contribution to the BKV-CIP Joint Venture, the Class B Member has received a total of 1,791,155 of the BKV-CIP Joint Venture's Class B Units at $10.00 per share.

Net income (loss) is allocated to each member pursuant to the BKV-CIP JV Agreement's liquidation provisions. For the year ended December 31, 2025, BKV dCarbon Ventures and the Class B Member's allocation in BKV-CIP Joint Venture's net income (loss) was 53% and 47%, respectively.

*BKV-BPP Cotton Cove Joint Venture*

On June 26, 2025, BKV dCarbon Ventures and BPPUS amended and restated the BKV-BPP Cotton Cove, LLC Agreement whereby on July 9, 2025, BKV dCarbon Ventures contributed $3.3 million to BKV-BPP Cotton Cove, net of $0.1 million of expenditures paid by BKV dCarbon Ventures on behalf of BKV-BPP Cotton Cove, and on July 10, 2025, BPPUS received $5.4 million of its initial capital contribution of $8.6 million from BKV-BPP Cotton Cove. Subsequent to these transactions, BKV dCarbon Ventures contributed an additional $5.8 million, for a total of $9.0 million, and BPPUS contributed an additional $5.5 million, for a total of $8.8 million, for the year ended December 31, 2025.

As of December 31, 2025, BKV dCarbon Ventures owns a 51% controlling interest in BKV-BPP Cotton Cove, with BPPUS retaining a 49% interest. The identifiable assets acquired and liabilities assumed were recorded at their estimated fair values as of the acquisition date, with the excess of the fair value of the net assets acquired over the consideration transferred recognized as noncontrolling interest within equity. On July 10, 2025, once the appropriate contributions were made to satisfy the BKV-BPP Cotton Cove LLC Agreement, the primary components of the assets acquired and liabilities assumed included the following (in thousands):

| | |
|---|---|
| **Consideration** | |
| Cash | $ 6,927 |
| Total consideration | 6,927 |
| | |
| **Assets acquired and liabilities assumed** | |
| Cash and cash equivalents | $ 2,077 |
| Account receivable, net | (624) |
| Other property, plant, and equipment, net | 5,535 |
| Accounts payable and accrued liabilities | (61) |
| Total net assets acquired | $ 6,927 |

Both the BKV-CIP Joint Venture and BKV-BPP Cotton Cove Joint Venture were formed to advance the Company's CCUS strategy and do not represent a material business combination under ASC 805, *Business Combination*, as the assets acquired and liabilities assumed were not significant to the Company's consolidated financial statements, and no goodwill or a bargain purchase gain was recognized.

***Variable Interest Entities***

The Company considers the BKV-BPP Power Joint Venture, the BKV-CIP Joint Venture, and the BKV-BPP Cotton Cove Joint Venture to each be a VIE in accordance with ASC 810, *Consolidation* as the Company is deemed to be the primary beneficiary of these joint ventures. Generally, a VIE is an entity with at least one of the following conditions: (i) the total equity investment at risk is insufficient to allow the entity to finance its activities without additional subordinated financial support, or (ii) the holders of the equity investment at risk, as a group, lack the characteristics of having a controlling financial interest. The primary beneficiary of a VIE is an entity that has a variable interest or a combination of variable interests that provide such entity with a controlling financial interest in the VIE. An entity is deemed to have a controlling financial interest in a VIE if it has both of the following characteristics: (i) the power to direct the activities of the VIE that most significantly impact the VIE's economic performance, and (ii) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE.

The Company's control over BKV-BPP Power is derived from its governance rights and its role in directing the day-to-day operational activities through its participation on a 12-member board of managers (the "BKV-BPP Power Board"), nine of whom are appointed by the Company and three of whom are appointed by BPPUS. The BKV-BPP Power Board has overall management and oversight of BKV-BPP Power, including approval of budgets, business plans, and key commercial and financing decisions. The Company directs plant operations, commercial optimization, fuel procurement, and marketing and risk management activities, through its operational role and participation in the governance of BKV-BPP Power. The Company's economic exposure is primarily based on its 75% ownership interest, which entitles it to a majority of distributions and results of operations and exposes it to a majority of potential losses. In addition, the Company is generally required to fund its proportionate share of capital contributions in accordance with the BKV-BPP Power LLC Agreement.

The assets of BKV-BPP Power may only be used to settle its obligations, and the liabilities of BKV-BPP Power do not have recourse to the general credit of the Company, except to the extent of the Company's investment and any contractual commitments. In addition, distributions from BKV-BPP Power may be subject to restrictions under its debt agreements or other contractual arrangements.

The Company's control over the BKV-CIP Joint Venture is derived from its ability to direct the development and execution of CCUS projects that most significantly impact the economic performance of this joint venture, including project development, capital deployment, and operational execution of CCUS projects through its management and oversight of these activities. The Company's economic exposure is based on its ownership interest and its obligation to absorb losses, or the right to receive benefits from the BKV-CIP Joint Venture.

The Company’s control over BKV-BPP Cotton Cove is derived from its majority ownership interest and governance rights, which provide the Company with the ability to direct the activities that most significantly impact the joint venture’s economic and operational performance, including the development and operation of CCUS-related assets. The Company’s economic exposure is based on its ownership interest, including its potential earnings and losses, including funding its proportionate share of capital contributions in accordance with the respective agreements.

The assets and liabilities of these consolidated VIEs are included within the respective line items of the Company’s consolidated balance sheets. The assets of the consolidated VIEs may only be used to settle obligations of the respective VIEs, and the liabilities of the consolidated VIEs do not have recourse to the general credit of the Company, except to the extent of the Company’s investment and any contractual commitments. The BKV-BPP Power Joint Venture, the BKV-CIP Joint Venture, and BKV-BPP Cotton Cove are exposed to similar operational risks as the Company, and are each monitored and evaluated on a similar basis by management. The carrying amounts and classification of the consolidated VIE assets and liabilities included in the consolidated balance sheets are as follows (excluding intercompany balances):

| | December 31, 2025 | | |
|---|---|---|---|
| **(in thousands)** | **BKV-BPP Power** | **BKV-CIP Joint Venture** | **BKV-BPP Cotton Cove** |
| Assets | | | |
| Current assets | | | |
| Cash and cash equivalents | $ 49,015 | $ 1,331 | $ 3,744 |
| Restricted cash | 15,846 | — | — |
| Accounts receivable, net | 28,618 | 11,749 | 568 |
| Other current assets | 30,360 | 654 | — |
| Total current assets | 123,839 | 13,734 | 4,312 |
| Other property, plant, and equipment, net | 806,673 | 55,452 | 16,606 |
| Other assets | 9,469 | — | — |
| Total assets | $ 939,981 | $ 69,186 | $ 20,918 |
| | | | |
| Liabilities | | | |
| Current liabilities | | | |
| Accounts payable and accrued liabilities | $ 22,553 | $ 4,880 | $ 2,269 |
| Other current liabilities | 18,374 | — | — |
| Total current liabilities | 40,927 | 4,880 | 2,269 |
| Other liabilities | 641,947 | — | — |
| Total liabilities | $ 682,874 | $ 4,880 | $ 2,269 |

| | December 31, 2024 |
|---|---|
| **(in thousands)** | **BKV-BPP Power** |
| Assets | |
| Current assets | |
| Cash and cash equivalents | $ 66,355 |
| Restricted cash | 15,775 |
| Accounts receivable, net | 21,202 |
| Other current assets | 37,533 |
| Total current assets | 140,865 |
| Other property, plant, and equipment, net | 839,497 |
| Other assets | 2,994 |
| Total assets | $ 983,356 |
| | |
| Liabilities | |
| Current liabilities | |
| Accounts payable and accrued liabilities | $ 41,158 |
| Other current liabilities | 29,836 |
| Total current liabilities | 70,994 |
| Other liabilities | 685,045 |
| Total liabilities | $ 756,039 |

***Noncontrolling Interests***

Noncontrolling interests held by BPPUS of 25% and 49% in BKV-BPP Power and BKV-BPP Cotton Cove, respectively, are presented as noncontrolling interest within equity on the consolidated balance sheets.

Pursuant to the BKV-CIP JV Agreement, the Class B Units are not mandatorily redeemable or currently redeemable, but become exercisable by the Class B Member with the passage of time beginning on May 8, 2027. The Company determined that there is an embedded put option in the Class B Units, which contains redemption features that are not solely within the control of the Company. Therefore, the shares of the BKV-CIP Joint Venture's Class B Units have been classified as noncontrolling interest within mezzanine equity on the Company's consolidated balance sheets. The redemption value of the Class B Units is based on a 1.65x multiple of invested capital, reduced by cumulative distributions made to the Class B Member. The contributions from the Class B Member are accreted to the redemption value over a period from issuance to the earliest redemption date (using the effective interest method) with the accretion accounted for as a dividend paid to the Class B Member. As of December 31, 2025, the carrying value of the Class B Units was $13.0 million, compared to an estimated redemption value of approximately $28.3 million.

As of December 31, 2025, distributions payable to Class B Member was $6.9 million, which represents 49% of the Section 45Q tax credits generated by BKV dCarbon Ventures in 2024. The distributions payable is included in accounts payable and accrued liabilities on the consolidated balance sheets.

**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").

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.

BKV-BPP Power relies on the Texas ERCOT system as the destination of produced energy in the State of Texas. If the Texas ERCOT system was not available to the Company, this would have a material adverse effect on the Company's financial results.

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, on occasion, proposed and if enacted, could adversely impact the Company's financial condition and results of operations.

Substantially all of the Company's accounts receivable, net result from the sale of natural gas, joint interest billings, and power sales. The Company sells the substantial majority of its 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, 2025 and 2024, one purchaser accounted for 62% and 51%, respectively, of accounts receivable - contracts with customers. For the year ended December 31, 2025, two customers each accounted for approximately 59% and 13%, respectively, of the Company's revenue from contracts with customers, totaling $675.9 million and $147.6 million, respectively. For the year ended December 31, 2024, three customers each accounted for approximately 47%, 18%, and 10%, respectively, of the Company's revenue from contracts with customers, totaling $380.6 million, $146.0 million, and $82.6 million, respectively. For the year ended December 31, 2023, the same three customers each accounted for approximately 47%, 17%, and 10%, respectively, of the Company's revenue from contracts with customers, totaling $476.5 million, $170.6 million, and $104.0 million, respectively. Additionally, for the year ended December 31, 2023, a fourth customer accounted for approximately 13% of the Company's revenue from contracts with customers, totaling $129.8 million. 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**

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. The Company accrues for a loss contingency when it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. If a loss is probable or reasonably possible, but the loss or range of loss cannot be reasonably estimated, the Company discloses the nature of the contingency, but does not accrue for the loss until a reasonable estimate or range becomes available. As of December 31, 2025, the Company has recorded an aggregate accrual of approximately $1.7 million, which is included in other current liabilities in the consolidated balance sheets.

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 recorded a contingent liability of $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, and on January 8, 2025, the Company paid the final 2024 contingent consideration of $20.0 million, which is reflected as contingent consideration payable within current liabilities on the consolidated balance sheets. 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. For the years ended December 31, 2024 and 2023, the changes in the fair value of the contingent consideration were gains of $7.5 million, and $25.0 million, respectively. These changes in the fair value during these periods impacted the associated liability on the consolidated balance sheets and the changes were recognized in the gains on contingent consideration liabilities on the consolidated statements of operations.

In conjunction with the Exxon Barnett Acquisition, additional cash consideration would have been 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, the fair value of the contingent consideration was zero. For the years ended December 31, 2024 and 2023, the changes in the fair value of the contingent consideration were gains of $2.2 million, and $13.4 million, respectively. These changes in the fair value during these periods reduced the associated liability on the consolidated balance sheets and the changes were 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 892,628,886 dekatherms of natural gas. The significant majority of the agreements terminate by 2029, with one agreement extending through 2036. As of December 31, 2025, the aggregate undiscounted future payments required under these contracts total $259.4 million.

BKV-BPP Power has commitment agreements with third parties to support the operation, fuel supply, and commercialization of its power generation assets. These agreements include energy management, fuel transportation and storage, operations and maintenance, and administrative service arrangements with terms expiring through 2028.

On November 1, 2017, BKV-BPP Power entered into a ten year firm natural gas transportation agreement for firm delivery quantity. As of December 31, 2025 and 2024, $0.3 million of imbalance penalties were included in accounts payable and accrued liabilities on the consolidated balance sheets. During the years ended December 31, 2025, 2024, and 2023, BKV-BPP Power incurred $3.4 million, $2.9 million, and $1.4 million, respectively of imbalance penalties, which were included in fuel commodity costs on the consolidated statements of operations.

A summary of the Company's commitments as of December 31, 2025, is provided in the following table:

| (in thousands) | 2026 | 2027 | 2028 | 2029 | 2030 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Temple Term Loan Facility | 10,000 | 10,000 | 381,883 | — | — | — | 401,883 |
| Temple Revolving Facility | — | — | 60,000 | — | — | — | 60,000 |
| Interest payable | 10,104 | — | — | — | — | — | 10,104 |
| BKV-BPP Power commitment agreements | 5,647 | 4,891 | 401 | — | — | — | 10,939 |
| Temple I Loan Agreements | 191,000 | — | — | — | — | — | 191,000 |
| Interest payable on Temple I Loan Agreements | 2,969 | — | — | — | — | — | 2,969 |
| Operating lease payments | 6,216 | 1,139 | 924 | 947 | 978 | 2,684 | 12,888 |
| Transportation commitments | 70,249 | 62,062 | 53,909 | 34,257 | 5,913 | 33,016 | 259,406 |
| **Total** | $ 296,185 | $ 78,092 | $ 497,117 | $ 35,204 | $ 6,891 | $ 35,700 | $ 949,189 |

**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) | 2025 | 2024 | 2023 |
| Current tax expense (benefit) | | | |
| United States federal income tax | $ (474) | $ 567 | $ — |
| Various state income taxes | (529) | 639 | (4,169) |
| Total current income tax expense (benefit) | (1,003) | 1,206 | (4,169) |
| Deferred tax expense (benefit) | | | |
| United States federal income tax | 38,126 | (43,445) | 31,338 |
| Various state taxes | (270) | (194) | 2,954 |
| Total deferred income tax expense (benefit) | 37,856 | (43,639) | 34,292 |
| Income tax expense (benefit) | $ 36,853 | $ (42,433) | $ 30,123 |

In 2025, the Company adopted ASU 2023-09, *Income Taxes: Improvement to Income Tax Disclosures* (see *Note 2 - Summary of Significant Accounting Policies*). The following table reconciles the provision for income taxes using the federal statutory rate to the Company's effective tax rate pursuant to the disclosure requirements of ASU 2023-09 for the years ended December 31, 2025, 2024, and 2023. Income tax expense (benefit) attributable to pre-tax income differed from the amounts computed by applying the U.S. federal statutory income tax rate of 21% to pre-tax income by the following:

| | Year Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2025 | | 2024 | | 2023 | |
| **($ in thousands)** | **Amount** | **Percent** | **Amount** | **Percent** | **Amount** | **Percent** |
| Income (loss) before income taxes | $ 225,169 | | $ (175,813) | | $ 162,146 | |
| U.S. federal tax at statutory tax rate | $ 47,285 | 21.0 % | $ (36,921) | 21.0 % | $ 34,051 | 21.0 % |
| State and local income taxes, net of federal income tax effect | (805) | (0.4)% | 100 | (0.1)% | (1,237) | (0.8)% |
| Tax credits | | | | | | |
| Investment tax credit | — | — % | (1,010) | 0.6 % | — | — % |
| Marginal well credit | (10,226) | (4.5)% | (7,644) | 4.3 % | (94) | (0.1)% |
| Nontaxable or nondeductible items | | | | | | |
| Section 162(m) limitation | 1,756 | 0.8 % | 8,881 | (5.1)% | — | — % |
| Excess tax benefits from vesting of restricted shares | (167) | (0.1)% | (3,829) | 2.2 % | (373) | (0.2)% |
| Section 45Q tax credits | (855) | (0.4)% | (2,944) | 1.7 % | (147) | (0.1)% |
| Other, net | (201) | (0.1)% | (967) | 0.6 % | 89 | 0.1 % |
| Other adjustments | 66 | — % | 1,901 | (1.1)% | (2,166) | (1.3)% |
| Income tax expense (benefit) | $ 36,853 | 16.4 % | $ (42,433) | 24.1 % | $ 30,123 | 18.6 % |

State taxes in Texas and Pennsylvania made up the majority of the tax effect in the state and local income taxes category. Income taxes paid (net of refunds) consisted of the following for the years ended December 31, 2025, 2024 and 2023:

| | Year Ended December 31, | | |
|---|---|---|---|
| **(in thousands)** | **2025** | **2024** | **2023** |
| Federal | $ — | $ — | $ — |
| State | 232 | 6 | 1,545 |
| Total taxes paid (net of refunds) | $ 232 | $ 6 | $ 1,545 |

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, 2025** | **December 31, 2024** |
|---|---|---|
| Deferred tax assets | | |
| Fair value of derivative financial instruments | $ — | $ 9,018 |
| Asset retirement obligations | 51,528 | 46,240 |
| Equity-based compensation | 1,649 | 494 |
| Contingent consideration | 353 | 4,597 |
| Interest expense carryforward | 34,836 | 33,029 |
| Net operating loss carryforward | 67,693 | 35,826 |
| Accrued bonuses | 5,226 | 4,218 |
| Marginal well credit | 23,669 | 13,180 |
| Other | 4,441 | 7,373 |
| Total deferred tax asset | 189,395 | 153,975 |
| Deferred tax liabilities | | |
| Property and equipment | (243,261) | (193,978) |
| Investment in joint venture | (56,344) | (50,287) |
| Fair value of derivative financial instruments | (15,240) | — |
| Other | (3,389) | (2,460) |
| Total deferred tax liability | (318,234) | (246,725) |
| Deferred tax liability, net | $ (128,839) | $ (92,750) |

As of December 31, 2025, the Company has an NOL carryforward deferred tax asset for federal tax purposes of $66.3 million, which does not expire and a NOL carryforward deferred tax asset for state tax purposes of $1.3 million, which expires between 2043 and 2045. In addition, as of December 31, 2025, the Company has a Section 163(j) interest expense carryforward deferred tax asset of $34.8 million, which does not expire, marginal well credits of $23.7 million that expire between 2040 and 2045, and investment tax credits of $1.0 million that expire in 2044. 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 were to experience an ownership change of more than 50% of the value of its capital stock, utilization of its NOL, interest expense, and tax credit carryforwards could be subject to limitation. As of December 31, 2025, management does not believe that the Company has experienced an ownership change, and therefore, does not believe that its NOL, Section 163(j) interest expense, and tax credit carryforwards are currently subject to limitation under Section 382.

Due to the proportional change in BNAC's beneficial ownership of the Company following the IPO, the Company was deconsolidated from BNAC for federal income tax purposes. In accordance with the Code and related regulations, the Company allocated the cumulative NOL carryforwards, Section 163(j) interest expense carryforwards, and other general business tax credits between BNAC and the Company. These allocations impacted the Company's deferred tax liability, net balance by increasing the NOL carryforward by $1.8 million and $14.3 million as of December 31, 2025 and 2024, respectively, and increasing general business tax credits by $2.5 million, while reducing the Section 163(j) interest expense carryforward by $6.3 million as of December 31, 2024. The net impact was recorded as an adjustment to additional paid-in capital, as reflected in the table above.

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, 2025 and 2024, 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, 2025, 2024, and 2023 and had no unrecognized tax benefit balances as of December 31, 2025 and 2024. The Company is generally subject to potential federal and state examination for the tax years on and after December 31, 2022. For Texas, the Company is subject to examination for the tax years on and after December 31, 2021.

**Note 18 - Earnings Per Share**

Basic net income (loss) per common share attributable to BKV for each period is calculated by dividing net income (loss) attributable to BKV, adjusted for accretion to redemption value of the Class B Units, by the basic weighted average number of common shares outstanding during the period. Diluted net income (loss) per common share attributable to BKV is calculated by dividing net income (loss) attributable to BKV, adjusted for accretion to redemption value of the Class B Units, by the diluted weighted average number of common shares outstanding for the respective period. Any remeasurement of the accretion to redemption value of the Class B Units subject to possible redemption was considered to be dividends paid to the Class B Member. Accordingly, accretion is deducted from net income (loss) in the calculation of earnings per share. 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 effect of all potential common shares was anti-dilutive.

The following is the calculation of basic and diluted net income (loss) per common share attributable to BKV for the years ended December 31, 2025, 2024, and 2023:

| | Year Ended December 31, | | |
|---|---|---|---|
| **(in thousands, except per share amounts)** | **2025** | **2024** | **2023** |
| Net income (loss) attributable to BKV | $ 179,156 | $ (138,651) | $ 123,556 |
| Accretion of Class B Units to redemption value | (1,422) | — | — |
| Net income (loss) including accretion of Class B Units to redemption value | $ 177,734 | $ (138,651) | $ 123,556 |
| | | | |
| Basic weighted average common shares outstanding | 86,581 | 71,288 | 60,730 |
| Add: dilutive effect of TRSUs | 173 | — | 172 |
| Add: dilutive effect of PRSUs | 69 | — | 3,478 |
| Diluted weighted average of common shares outstanding | 86,823 | 71,288 | 64,380 |
| Weighted average number of outstanding securities excluded from the calculation of diluted loss per share | | | |
| TRSUs | — | 264 | — |
| PRSUs | — | 2,523 | — |
| | | | |
| Net income (loss) per common share attributable to BKV: | | | |
| Basic | $ 2.05 | $ (1.94) | $ 2.03 |
| Diluted | $ 2.05 | $ (1.94) | $ 1.92 |

**Note 19 - Reportable Segments**

Effective January 30, 2026, the Company completed the acquisition of an additional 25% ownership interest in the BKV-BPP Power Joint Venture from BPPUS in a transaction between entities under common control. As a result, the Company retrospectively adjusted its consolidated financial statements in accordance with ASC 805-50 to reflect the BKV-BPP Power Joint Venture as if it had been consolidated for all periods presented. Consequently, the Company revised its reportable segments and retrospectively recast prior-period segment information to conform to the current presentation.

The Company's natural gas production, natural gas midstream, and power generation business lines, all of which are located within the United States, are organized into two reportable segments for financial reporting purposes: (i) Upstream/Midstream and (ii) Power. In addition, the Company has an "All Other" category, which includes its Corporate and Other operating segment. The Corporate and Other operating segment includes the Company's remaining non-reportable segment operations consisting primarily of its CCUS business line and general corporate expenses not allocated to its reportable segments.

The CODM evaluates the financial results of each of the reportable segments, primarily segment revenues, significant segment expenses, and other segment items, and allocates resources, manages liquidity, and assesses overall Company performance relative to budget. The CODM also monitors total assets and capital expenditures by segment.

The Company's Upstream/Midstream segment is engaged in the acquisition, operation, exploration, development, and production of natural gas, NGLs, and oil in the Barnett and NEPA, and the commercial and midstream services such as gathering and transportation, marketing services, and commodity risk management activities.

The Company's Power segment is engaged in electricity generation, wholesale energy sales and purchases, and retail marketing operations. These activities are conducted through the BKV-BPP Power Joint Venture in which the Company holds a 75% ownership interest. Subsidiaries of the BKV-BPP Power Joint Venture own the Temple Plants, which are modern combined-cycle gas and steam turbine power plants located in the ERCOT North Zone in Temple, Texas, and operate a retail marketing business throughout the deregulated portions of Texas.

The Company's Corporate and Other operating segment includes BKV Corp, shared services, and the results of the Company's carbon capture and sequestration business, which focuses on reducing GHG emissions by capturing $CO_2$ from Company-owned and third-party operations, as well as other energy and industrial sources. Transactions between reportable segments are primarily related to administrative services provided under intercompany service agreements and are recorded based on the costs specified in those agreements. Intercompany eliminations are included within the Corporate and Other segment for purposes of segment reporting.

The following tables present the Company's segment revenues and other operating income, significant segment operating expenses, and segment income (loss) from operations:

| | Year Ended December 31, 2025 | | | | |
|---|---|---|---|---|---|
| (in thousands) | Upstream/ Midstream | Power | Total Reportable Segments | Corporate and Other | Total |
| Revenues and other operating income | | | | | |
| Natural gas, NGL, and oil sales | $ 857,597 | $ — | $ 857,597 | $ — | $ 857,597 |
| Power revenues | — | 248,752 | 248,752 | — | 248,752 |
| Midstream revenues | 10,456 | — | 10,456 | — | 10,456 |
| Derivative gains (losses), net | 105,081 | 274,788 | 379,869 | — | 379,869 |
| Marketing revenues | — | — | — | 12,304 | 12,304 |
| Section 45Q tax credits | — | — | — | 11,752 | 11,752 |
| Loss on sales of assets | (1,798) | — | (1,798) | (7) | (1,805) |
| Other | 11,664 | — | 11,664 | — | 11,664 |
| Total revenues and other operating income | $ 983,000 | $ 523,540 | $ 1,506,540 | $ 24,049 | $ 1,530,589 |
| Operating expenses | | | | | |
| Lease operating and workover | 152,873 | — | 152,873 | — | 152,873 |
| Fuel commodity costs | — | 180,364 | 180,364 | — | 180,364 |
| Purchased power | — | 113,968 | 113,968 | — | 113,968 |
| Taxes other than income | 50,761 | 15,645 | 66,406 | 1 | 66,407 |
| Gathering and transportation | 250,849 | — | 250,849 | — | 250,849 |
| Depreciation, depletion, amortization, and accretion | 155,713 | 38,273 | 193,986 | 1,751 | 195,737 |
| General and administrative | 68,944 | 19,999 | 88,943 | 42,629 | 131,572 |
| Power operating and maintenance | — | 78,435 | 78,435 | — | 78,435 |
| Other operating expenses | 29,034 | 8,296 | 37,330 | 19,344 | 56,674 |
| Total operating expenses | 708,174 | 454,980 | 1,163,154 | 63,725 | 1,226,879 |
| Income (loss) from operations | $ 274,826 | $ 68,560 | $ 343,386 | $ (39,676) | $ 303,710 |
| Capital expenditures | $ 258,549 | $ 4,954 | $ 263,503 | $ 41,616 | $ 305,119 |

| (in thousands) | Year Ended December 31, 2024<br>Upstream/ Midstream | Power | Total Reportable Segments | Corporate and Other | Total |
|---|---|---|---|---|---|
| Revenues and other operating income | | | | | |
| Natural gas, NGL, and oil sales | $ 557,570 | $ — | $ 557,570 | $ — | $ 557,570 |
| Power revenues | — | 218,268 | 218,268 | — | 218,268 |
| Midstream revenues | 12,560 | — | 12,560 | — | 12,560 |
| Derivative gains (losses), net | (34,152) | 241,612 | 207,460 | — | 207,460 |
| Marketing revenues | — | — | — | 10,668 | 10,668 |
| Section 45Q tax credits | — | — | — | 14,021 | 14,021 |
| Gain on sale of business | 7,080 | — | 7,080 | — | 7,080 |
| Gain on sales of assets | 3,523 | — | 3,523 | — | 3,523 |
| Other | 6,631 | — | 6,631 | — | 6,631 |
| Total revenues and other operating income | $ 553,212 | $ 459,880 | $ 1,013,092 | $ 24,689 | $ 1,037,781 |
| Operating expenses | | | | | |
| Lease operating and workover | 136,991 | — | 136,991 | — | 136,991 |
| Fuel commodity costs | — | 118,662 | 118,662 | — | 118,662 |
| Purchased power | — | 108,327 | 108,327 | — | 108,327 |
| Taxes other than income | 34,961 | 12,843 | 47,804 | 48 | 47,852 |
| Gathering and transportation | 222,391 | — | 222,391 | — | 222,391 |
| Depreciation, depletion, amortization, and accretion | 215,541 | 37,967 | 253,508 | 1,992 | 255,500 |
| General and administrative | 59,417 | 14,524 | 73,941 | 36,090 | 110,031 |
| Power operating and maintenance | — | 81,071 | 81,071 | — | 81,071 |
| Other operating expenses | 12,647 | 1,809 | 14,456 | 6,738 | 21,194 |
| Total operating expenses | 681,948 | 375,203 | 1,057,151 | 44,868 | 1,102,019 |
| Loss from operations | $ (128,736) | $ 84,677 | $ (44,059) | $ (20,179) | $ (64,238) |
| Capital expenditures | $ 88,384 | $ 4,445 | $ 92,829 | $ 12,532 | $ 105,361 |

| (in thousands) | Year Ended December 31, 2023<br>Upstream/ Midstream | Power | Total Reportable Segments | Corporate and Other | Total |
|---|---|---|---|---|---|
| Revenues and other operating income | | | | | |
| Natural gas, NGL, and oil sales | $ 706,151 | $ — | $ 706,151 | $ — | $ 706,151 |
| Power revenues | — | 274,623 | 274,623 | — | 274,623 |
| Midstream revenues | 16,168 | — | 16,168 | — | 16,168 |
| Derivative gains (losses), net | 238,743 | 51,981 | 290,724 | — | 290,724 |
| Marketing revenues | — | — | — | 8,710 | 8,710 |
| Section 45Q tax credits | — | — | — | 701 | 701 |
| Gain on sales of assets | 2,162 | — | 2,162 | 45 | 2,207 |
| Other | 3,957 | — | 3,957 | — | 3,957 |
| Total revenues and other operating income | $ 967,181 | $ 326,604 | $ 1,293,785 | $ 9,456 | $ 1,303,241 |
| Operating expenses | | | | | |
| Lease operating and workover | 150,647 | — | 150,647 | — | 150,647 |
| Fuel commodity costs | — | 94,213 | 94,213 | — | 94,213 |
| Purchased power | — | 27,769 | 27,769 | — | 27,769 |
| Taxes other than income | 72,290 | 8,827 | 81,117 | — | 81,117 |
| Gathering and transportation | 248,990 | — | 248,990 | — | 248,990 |
| Depreciation, depletion, amortization, and accretion | 223,165 | 31,752 | 254,917 | 205 | 255,122 |
| General and administrative | 65,852 | 27,917 | 93,769 | 39,805 | 133,574 |
| Power operating and maintenance | — | 56,365 | 56,365 | — | 56,365 |
| Other operating expenses | 12,353 | 1,671 | 14,024 | 272 | 14,296 |
| Total operating expenses | 773,297 | 248,514 | 1,021,811 | 40,282 | 1,062,093 |
| Income from operations | $ 193,884 | $ 78,090 | $ 271,974 | $ (30,826) | $ 241,148 |
| Capital expenditures | $ 137,085 | $ 13,797 | $ 150,882 | 50,631 | $ 201,513 |

The following table reconciles total segment income (loss) from operations to consolidated income before income taxes

| (in thousands) | Year Ended December 31, 2025 | 2024 | 2023 |
|---|---|---|---|
| Total segment operating income (loss) | $ 343,386 | $ (44,059) | $ 271,974 |
| Unallocated amounts: | | | |
| Corporate and Other revenues and other operating income | 24,049 | 24,689 | 9,456 |
| Corporate and Other taxes other than income | (1) | (48) | — |
| Corporate and Other depreciation, depletion, amortization, and accretion | (1,751) | (1,992) | (205) |
| Corporate and Other general and administrative | (42,629) | (36,090) | (39,805) |
| Corporate and Other other operating expenses | (19,344) | (6,738) | (272) |
| Gains on contingent consideration liabilities | — | 9,676 | 38,375 |
| Interest expense, net | (87,876) | (116,369) | (122,820) |
| Loss on extinguishment of debt | — | (13,877) | — |
| Other income | 9,335 | 8,995 | 5,443 |
| Income (loss) before income taxes | $ 225,169 | $ (175,813) | $ 162,146 |

The following table presents total assets by reportable segment reconciled to total consolidated assets:

| (in thousands) | December 31, 2025 | 2024 |
|---|---|---|
| Upstream/Midstream | $ 2,670,434 | $ 2,016,352 |
| Power | 939,981 | 983,356 |
| Total reportable segments | 3,610,415 | 2,999,708 |
| Corporate and Other | 328,842 | 99,069 |
| Total consolidated assets | $ 3,939,257 | $ 3,098,777 |

**Note 20 - Subsequent Events**

On January 14, 2026, the Company entered into a manufacturing reservation agreement related to a planned power generation project. Under the agreement, the Company is committed to pay up to an aggregate of $80.0 million in reservation fees, scheduled in phases during 2026, to secure future manufacturing capacity through 2028 for turbines with up to approximately 1,230 megawatts in total generation capacity. Amounts paid are generally non-refundable and will be credited against the purchase price if a definitive supply agreement is executed.

On January 30, 2026, the Company completed the previously announced acquisition of an additional 25% interest in the BKV-BPP Power Joint Venture for aggregate consideration of $115.1 million in cash and 5,315,390 shares of Company common stock, which shares are subject to a 180-day lock-up. The aggregate purchase price was equal to (x) $376.0 million, less (y) 25% of BKV-BPP Power's net indebtedness at the closing, payable 50% in cash and 50% in shares of the Company's common stock. BKV-BPP Power's net indebtedness was $582.9 million as of the closing date and the number of shares issued was determined by dividing the 50% of the aggregate purchase price by $21.6609, which represents the volume-weighted average price of the Company's common stock during the 20 consecutive trading day period ended October 28, 2025. The Company funded the cash consideration for the transaction with a combination of cash on hand and the net proceeds from the underwritten public equity offering of 6,900,000 shares of Company common stock completed on December 3, 2025. Following the closing of the transaction, the Company and BPPUS own 75% and 25% of the BKV-BPP Power Joint Venture, respectively, and the Company consolidated the financial results of BKV-BPP Power into the Company's consolidated financial results.

Also on January 30, 2026, the Company amended and restated its administrative service agreement with BKV-BPP Power LLC, effective January 1, 2026, to provide continued and updated administrative services and support to BKV-BPP Power. The amended and restated administrative service agreement has an initial term through December 31, 2026, and renews annually on January 1 for additional one-year terms unless mutually terminated. Fees under the administrative service agreement are reviewed and updated annually and are assessed based on services provided.

**Note 21 - 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:

| (in thousands) | December 31, 2025 | December 31, 2024 |
|---|---|---|
| Developed properties | $ 2,965,638 | $ 2,315,167 |
| Undeveloped properties | 13,182 | 10,757 |
| Total capitalized costs | 2,978,820 | 2,325,924 |
| Less: accumulated depreciation, depletion, and amortization | (825,694) | (697,002) |
| Net capitalized costs | $ 2,153,126 | $ 1,628,922 |

***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:

| (in thousands) | Year Ended December 31, 2025 | 2024 | 2023 |
|---|---|---|---|
| Undeveloped property acquisition costs | $ 2,425 | $ 775 | $ 335 |
| Acquisitions [1] | 392,626 | — | 9,885 |
| Development costs | 259,364 | 95,427 | 107,544 |
| Total cost incurred | 654,415 | 96,202 | 117,764 |
| Asset retirement obligations | 226 | 42 | 89 |
| Total costs incurred including asset retirement obligations | $ 654,641 | $ 96,244 | $ 117,853 |

(1) For the year ended December 31, 2025, acquisition costs include the natural gas properties acquired in the Bedrock Acquisition, and for the year ended December 31, 2023, acquisition costs include the mineral interests in acquired wells and additional costs related to previous acquisitions.

The Company’s oil and gas producing activities are included within its Upstream/Midstream reportable segment. The results of operations from natural gas and oil producing activities are not materially different from the applicable amounts presented within the consolidated financial statements and related segment disclosures. 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 and for the years ended December 31, 2025, 2024, and 2023, 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, reserve estimates are subject to periodic revision. 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, 2023 | 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 |
| Revision of previous estimates | 1,753,200 | 73,155 | 1,472 | 2,200,960 |
| Extensions and discoveries | 118,208 | 1,891 | — | 129,554 |
| Improved recoveries | 18,109 | 407 | 1 | 20,560 |
| Purchases of minerals in place | 463,147 | 45,762 | 876 | 742,978 |
| Production | (242,931) | (10,181) | (159) | (304,975) |
| December 31, 2025 | 4,345,764 | 258,656 | 3,881 | 5,920,986 |
| Proved developed reserves as of: | | | | |
| January 1, 2023 | 2,443,072 | 156,399 | 992 | 3,387,418 |
| December 31, 2024 | 2,059,983 | 134,016 | 878 | 2,869,347 |
| December 31, 2025 | 3,097,864 | 183,111 | 1,763 | 4,207,108 |
| Proved undeveloped reserves as of: | | | | |
| January 1, 2023 | 539,423 | 27,766 | 59 | 706,373 |
| December 31, 2024 | 176,048 | 13,606 | 813 | 262,562 |
| December 31, 2025 | 1,247,900 | 75,545 | 2,118 | 1,713,878 |

| (in MMcfe) | Developed | Undeveloped | Total |
|---|---|---|---|
| January 1, 2023 | 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 |
| Net sales 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 |
| Revision of previous estimates | 915,783 | 1,285,177 | 2,200,960 |
| Extensions and discoveries | — | 129,554 | 129,554 |
| Improved recoveries | 20,560 | — | 20,560 |
| Purchases of minerals in place | 494,590 | 248,388 | 742,978 |
| Production | (304,975) | — | (304,975) |
| Undeveloped reserves converted to developed | 211,803 | (211,803) | — |
| December 31, 2025 | 4,207,108 | 1,713,878 | 5,920,986 |

***2025 Activity***

During the year ended December 31, 2025, the Company's proved reserves increased by 2,789.1 Bcfe. The increase in proved reserves was primarily attributable to increased commodity pricing and drilling activity, which resulted in total upward revisions of 2,201.0 Bcfe. In addition, in September 2025, BKV Upstream Midstream acquired 100% of the equity interests of BKV Barnett II (formerly known as Bedrock Production, LLC), increasing reserves by 743.0 Bcfe. Extensions and discoveries and improved recoveries experienced by the Company in 2025 also resulted in net increases to proved reserves of 129.6 Bcfe and 20.6 Bcfe, respectively. The Company produced 305.0 Bcfe during the year ended December 31, 2025.

*Revisions of previous estimates* — Primarily consisted of upward revisions to proved developed reserves and proved undeveloped reserves of 915.8 Bcfe and 679.2 Bcfe, respectively, as a result of higher average pricing during 2025 for natural gas, NGLs, and oil. Additional upward revisions were made to proved undeveloped reserves of 599.2 Bcfe due to increases in capital spend and drilling activity during 2025. Changes to the Company's drilling schedule added 86.0 gross (81.2 net) proved locations in NEPA and the Barnett to be developed within 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 129.6 Bcfe of proved undeveloped reserves across 11.0 gross (8.9 net) locations driven by the Company's optimized capital allocation and enhanced drilling program, which reduced costs and extended lateral lengths during the year ended December 31, 2025.

*Improved recoveries* — Added 20.6 Bcfe of proved developed reserves achieved through the continued enhancement of recovery techniques applied to producing wells during the year ended December 31, 2025.

*Purchases of minerals in place* — Consisted of 494.6 Bcfe and 248.4 Bcfe of acquired proved developed reserves and proved undeveloped reserves, respectively, from the Bedrock Acquisition, which represented 1,002.0 gross (877.6 net) locations in the Barnett.

*Conversions of proved undeveloped reserves to proved developed reserves* — Consisted of 211.8 Bcfe related to the completion of 34.0 gross (31.0 net) wells during the year ended December 31, 2025 that were converted to proved developed wells, previously classified as proved undeveloped. Estimated future development costs relating to the development of the Company's proved undeveloped reserves were $1.0 billion for the year ended December 31, 2025.

***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 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 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 139.2 Bcfe of proved undeveloped reserves across 16.0 gross (14.4 net) locations, driven by the Company's optimized capital allocation and enhanced drilling program, which reduced costs and extended lateral lengths during the year ended December 31, 2024.

*Improved recoveries* — Consisted of 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.

*Sales 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.

***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 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* — 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 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 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 its 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.

***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 reserves as of the periods presented:

| **Future cash flows (in thousands)** | **Year Ended December 31, 2025** | **2024** | **2023** |
|---|---|---|---|
| Future cash inflows | $ 16,928,259 | $ 6,207,197 | $ 9,691,057 |
| Future production costs | (8,616,382) | (4,026,521) | (5,799,209) |
| Future development costs [1] | (1,657,625) | (666,194) | (977,333) |
| Future income tax expense | (1,111,793) | (96,180) | (406,937) |
| Future net cash flows | 5,542,459 | 1,418,302 | 2,507,578 |
| 10% annual discount for estimated timing of cash flows | (3,197,795) | (785,216) | (1,445,245) |
| Standardized measure of discounted future net cash flows related to proved reserves | $ 2,344,664 | $ 633,086 | $ 1,062,333 |

(1) Includes abandonment costs.

The following table summarizes the changes in the Standardized Measure:

| **(in thousands)** | **Year Ended December 31, 2025** | **2024** | **2023** |
|---|---|---|---|
| Balance, beginning of period | $ 633,086 | $ 1,062,333 | $ 6,993,602 |
| Net change in sales and transfer prices and in production (lifting) costs related to future production | 943,628 | (272,270) | (5,386,961) |
| Changes in estimated future development costs | (37,067) | (2,933) | 91,657 |
| Sales and transfers of natural gas, NGLs, and oil produced during the period | (381,138) | (271,692) | (201,884) |
| Net change due to extensions, discoveries, and improved recoveries | 75,400 | 18,261 | 36,107 |
| Net change due to purchases (sales) of minerals in place | 337,761 | (90,531) | — |
| Net change due to revisions in quantity estimates | 1,007,937 | (74,031) | (3,058,900) |
| Previously estimated development costs incurred during the period | 21,467 | 24,291 | 27,598 |
| Net change in future income taxes | (404,531) | 131,401 | 1,790,684 |
| Accretion of discount | 67,190 | 123,255 | 861,914 |
| Changes in timing and other | 80,931 | (14,998) | (91,484) |
| Total discounted cash flow as end of period | $ 2,344,664 | $ 633,086 | $ 1,062,333 |

## ITEM 9A. CONTROLS AND PROCEDURES

### Evaluation of Disclosure Controls and Procedures

As required by Rules 13a-15(b) and 15d-15(b) under 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 the design and operation 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 SEC'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 disclosures. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective at a reasonable assurance level as of December 31, 2025.

### Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the criteria established in *Internal Control-Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2025.

This Annual Report on Form 10-K does not include an attestation report of our independent registered public accounting firm regarding internal control over financial reporting as we qualify as an "emerging growth company" as of December 31, 2025.

### Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the three months ended December 31, 2025 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

## 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 | 11/18/2022 | |
| 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 | 11/18/2022 | |
| 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 | 11/18/2022 | |
| 2.4+‡ | Membership Interest Purchase Agreement, dated as of August 7, 2025, by and among BKV Upstream Midstream, LLC, Bedrock Energy Partners, LLC, certain of its subsidiaries and, solely for certain limited purposes set forth herein, BKV Corporation. | 10-Q | 001-42282 | 2.1 | 11/10/2025 | |
| 2.5+ | Membership Interest Purchase Agreement, dated as of October 29, 2025, by and between BKV Corporation and Banpu Power US Corporation. | 10-Q | 001-42282 | 2.2 | 11/10/2025 | |
| 3.1 | Second Amended and Restated Certificate of Incorporation of BKV Corporation. | 8-K | 001-42282 | 3.1 | 9/27/2024 | |
| 3.2 | Second Amended and Restated Bylaws of BKV Corporation. | 8-K | 001-42282 | 3.2 | 9/27/2024 | |
| 4.1 | Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934. | 10-K | 001-42282 | 4.1 | 3/6/2026 | |

| | | | | | |
|---|---|---|---|---|---|
| 4.2 | Indenture, dated as of September 26, 2025, by and among BKV Upstream Midstream, LLC, the guarantors party thereto and U.S. Bank Trust Company, National Association, as trustee (including Form of Note). | 8-K | 001-42282 | 4.1 | 10/1/2025 |
| 4.3 | First Supplemental Indenture, dated as of September 29, 2025, by and among BKV Upstream Midstream, LLC, Bedrock Production, LLC, Bedrock Development Partners, LLC, Bedrock ABS I Holdings, LLC, Bedrock ABS I, LLC and U.S. Bank Trust Company, National Association, as trustee. | 8-K | 001-42282 | 4.2 | 10/1/2025 |
| 10.1† | Employment Agreement, dated August 4, 2020, between BKV Corporation and Christopher P. Kalnin. | S-1 | 377-06312 | 10.16 | 8/12/2022 |
| 10.2† | Employment Agreement, dated February 18, 2020, between Kalnin Ventures LLC and Eric Jacobsen. | S-1 | 377-06312 | 10.18 | 8/12/2022 |
| 10.3† | Employment Agreement, dated October 15, 2018, between Kalnin Ventures LLC and Lindsay B. Larrick. | S-1 | 377-06312 | 10.20 | 8/12/2022 |
| 10.4† | Employment Agreement, dated April 1, 2018, between Kalnin Ventures LLC and An Sao (Ethan) Ngo. | S-1 | 377-06312 | 10.21 | 8/12/2022 |
| 10.5† | Limited Liability Company Agreement of BKV-BPP Power LLC dated October 29, 2021. | S-1 | 377-06312 | 10.22 | 8/12/2022 |
| 10.6† | BKV Corporation Non-Employee Director Compensation Program. | S-1 | 377-06312 | 10.24 | 9/16/2022 |
| 10.7† | Letter Agreement, dated November 14, 2022, between Kalnin Ventures, LLC and Barry Turcotte. | S-1 | 333-268469 | 10.31 | 12/22/2022 |
| 10.8† | Employment Agreement, effective October 9, 2023, between BKV Corporation and Mary Rita Valois. | S-1 | 333-268469 | 10.42 | 1/12/2024 |
| 10.9 | 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 | 7/5/2024 |
| 10.10 | Stockholders' Agreement, dated September 27, 2024, by and between BKV Corporation and Banpu North America Corporation. | 8-K | 001-42282 | 10.1 | 9/27/2024 |
| 10.11 | 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 | 9/27/2024 |

| | | | | | |
|---|---|---|---|---|---|
| 10.12† | BKV Corporation 2024 Equity and Incentive Compensation Plan (the “2024 Plan”). | 8-K | 001-42282 | 10.3 | 9/27/2024 |
| 10.13† | Time Restricted Stock Unit Award Notice and Award Agreement under the 2024 Plan (CEO). | 8-K | 001-42282 | 10.4 | 9/27/2024 |
| 10.14† | Performance-Based Restricted Stock Unit Award Notice and Award Agreement under the 2024 Plan (CEO). | 8-K | 001-42282 | 10.5 | 9/27/2024 |
| 10.15† | Time Restricted Stock Unit Award Notice and Award Agreement under the 2024 Plan (Non-CEO Employee). | 8-K | 001-42282 | 10.6 | 9/27/2024 |
| 10.16† | Performance-Based Restricted Stock Unit Award Notice and Award Agreement under the 2024 Plan (Non-CEO Employee). | 8-K | 001-42282 | 10.7 | 9/27/2024 |
| 10.17† | Restricted Stock Unit Award Notice and Award Agreement under the 2024 Plan (Director). | 8-K | 001-42282 | 10.8 | 9/27/2024 |
| 10.18† | Form of Director and Officer Indemnity Agreement. | 8-K | 001-42282 | 10.9 | 9/27/2024 |
| 10.19† | Transition and Mutual Separation Agreement, dated as of February 3, 2025, between BKV Corporation and John T. Jimenez. | 8-K | 001-42282 | 10.1 | 2/3/2025 |
| 10.20† | Employment Agreement, dated as of February 3, 2025, between BKV Corporation and David R. Tameron. | 8-K | 001-42282 | 10.2 | 2/3/2025 |
| 10.21† | Amended and Restated Employment Agreement, dated as of February 3, 2025, between BKV Corporation and Eric S. Jacobsen. | 8-K | 001-42282 | 10.3 | 2/3/2025 |
| 10.22 | Second Amendment to Credit Agreement, dated as of May 6, 2025 among BKV Corporation, BKV Upstream Midstream, LLC, Citibank, N.A., and the Lenders party thereto. | 10-Q | 001-42282 | 10.4 | 5/9/2025 |
| 10.23‡ | Limited Liability Company Agreement of BKV dCarbon Project, LLC dated as of May 8, 2025 by BKV dCarbon Ventures, LLC and C Squared Solutions, Inc. and for the limited purposes specified herein, BKV Corporation. | 10-Q | 001-42282 | 10.2 | 8/12/2025 |
| 10.24 | Third Amendment to Credit Agreement, dated as of September 22, 2025, among BKV Corporation, as guarantor, BKV Upstream Midstream, LLC, as borrower, certain subsidiaries of BKV Upstream Midstream, LLC, as guarantors, Citibank, N.A., as administrative agent, and the lenders party thereto. | 8-K | 001-42282 | 10.1 | 9/22/2025 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 10.25 | Registration Rights Agreement, dated as of September 29, 2025, by and between BKV Corporation and Bedrock Energy Partners, LLC. | 10-Q | 001-42282 | 10.2 | 11/10/2025 | |
| 10.26+ | Fourth Amendment to Credit Agreement, dated as of October 27, 2025, among BKV Corporation, as guarantor, BKV Upstream Midstream, LLC, as borrower, certain subsidiaries of BKV Upstream Midstream, LLC, as guarantors, Citibank, N.A., as administrative agent, and the lenders party thereto. | 10-Q | 001-42282 | 10.3 | 11/10/2025 | |
| 10.27 | Registration Rights Agreement, dated as of January 30, 2026, by and between BKV Corporation and Banpu Power US Corporation. | 8-K | 001-42282 | 10.1 | 1/30/2026 | |
| 10.28+ | Amended and Restated Limited Liability Company Agreement of BKV-BPP Power LLC, dated as of January 30, 2026. | 8-K | 001-42282 | 10.2 | 1/30/2026 | |
| 10.29† | Amended and Restated BKV Corporation 2024 Equity and Incentive Compensation Plan. | 10-K | 001-42282 | 10.29 | 3/6/2026 | |
| 10.30† | Employment Agreement, dated as of April 3, 2025, between BKV Corporation and Dilanka Seimon. | 10-K | 001-42282 | 10.30 | 3/6/2026 | |
| 19.1 | Insider Trading Policies and Procedures. | 10-K | 001-42282 | 19.1 | 3/31/2025 | |
| 21.1 | List of Subsidiaries of BKV Corporation. | 10-K | 001-42282 | 21.1 | 3/6/2026 | |
| 23.1 | Consent of PricewaterhouseCoopers LLP. | | | | | X |
| 23.2 | Consent of Ryder Scott Company, L.P. | 10-K | 001-42282 | 23.2 | 3/6/2026 | |
| 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. | 10-K | 001-42282 | 97.1 | 3/31/2025 | |
| 99.1 | Ryder Scott Company, L.P., Summary of Reserves at December 31, 2025(SEC Pricing) (Total Company Assets). | 10-K | 001-42282 | 99.1 | 3/6/2026 | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 99.2 | Ryder Scott Company, L.P., Summary of Reserves at December 31, 2025(NYMEX Pricing) (Total Company Assets). | 10-K | 001-42282 | 99.2 | 3/6/2026 | |
| 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

**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: August 19, 2026

By: /s/ David R. Tameron
David R. Tameron
Chief Financial Officer
(Principal Financial Officer)

**Exhibit 23.1**

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (Nos. 333-290676 and 333-292408) and Form S-8 (Nos. 333-282383 and 333-294116) of BKV Corporation of our report dated March 6, 2026, except for the effects of an acquisition of a business between entities under common control and the change in the reportable segments discussed in Notes 1 and 19 to the consolidated financial statements, respectively, as to which the date is August 19, 2026, relating to the financial statements, which appears in this Form 10-K/A.

/s/ PricewaterhouseCoopers LLP

Dallas, Texas

August 19, 2026

**Exhibit 31.1**

**CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER**

I, Christopher P. Kalnin, certify that:

1. I have reviewed this Annual Report on Form 10-K/A of BKV Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: August 19, 2026

/s/ Christopher P. Kalnin
Christopher P. Kalnin
Chief Executive Officer
Principal Executive Officer

**Exhibit 31.2**

**CERTIFICATION OF THE CHIEF FINANCIAL OFFICER**

I, David R. Tameron, certify that:

1. I have reviewed this Annual Report on Form 10-K/A of BKV Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 19, 2026

/s/ David R. Tameron
David R. Tameron
Chief Financial Officer
Principal Financial Officer

**Exhibit 32.1**

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, I, Christopher P. Kalnin, the Chief Executive Officer of BKV Corporation (the “Company”), hereby certify, that, to the best of my knowledge:

(1) The Annual Report on Form 10-K/A of the Company for the period ended December 31, 2025, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: August 19, 2026

/s/ Christopher P. Kalnin
Christopher P. Kalnin
Chief Executive Officer
Principal Executive Officer

**Exhibit 32.2**

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, I, David R. Tameron, the Chief Financial Officer of BKV Corporation (the “Company”), hereby certify, that, to the best of my knowledge:

(1) The Annual Report on Form 10-K/A of the Company for the period ended December 31, 2025, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: August 19, 2026

/s/ David R. Tameron
David R. Tameron
Chief Financial Officer
Principal Financial Officer