



2025

ANNUAL REPORT

ALLIANCE RESOURCE PARTNERS, L.P.

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

FORM 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE FISCAL YEAR ENDED DECEMBER 31, 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 NO.: 0-26823

ALLIANCE RESOURCE PARTNERS, L.P.

(EXACT NAME OF REGISTRANT AS SPECIFIED IN ITS CHARTER)

Delaware
(State or Other Jurisdiction of
Incorporation or Organization)

73-1564280
(IRS Employer Identification No.)

1717 South Boulder Avenue, Suite 400, Tulsa, Oklahoma 74119

(Address of Principal Executive Offices and Zip Code)

(918) 295-7600

(Registrant's Telephone Number, Including Area Code)

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

Title of Each Class	Trading Symbol	Name of Each Exchange On Which Registered
Common Units representing limited partner interests	ARLP	The NASDAQ Stock Market LLC

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. ☒ Yes ☐ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. ☐ Yes ☒ No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☒ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). ☒ Yes ☐ No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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 ☐

(Do not check if 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. 726(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 Exchange Act). ☐ Yes ☒ No

The aggregate value of the common units held by non-affiliates of the registrant (treating all executive officers and directors of the registrant, for this purpose, as if they may be affiliates of the registrant) was \$2,791,674,155 as of June 30, 2025, the last business day of the registrant's most recently completed second fiscal quarter, based on the reported closing price of the common units as reported on The NASDAQ Stock Market LLC on such date.

As of February 26, 2026, 128,658,801 common units were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: None

TABLE OF CONTENTS

	Page
PART I	
Item 1. Business	1
Item 1A. Risk Factors	26
Item 1B. Unresolved Staff Comments	55
Item 1C. Cybersecurity	56
Item 2. Properties	59
Item 3. Legal Proceedings	78
Item 4. Mine Safety Disclosures	78
PART II	
Item 5. Market for Registrant’s Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities	79
Item 6. [Reserved]	79
Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations	80
Item 7A. Quantitative and Qualitative Disclosures about Market Risk	93
Item 8. Financial Statements and Supplementary Data	95
Report of Independent Registered Public Accounting Firm (PCAOB ID Number 248)	96
Consolidated Balance Sheets	98
Consolidated Statements of Income	99
Consolidated Statements of Comprehensive Income	100
Consolidated Statements of Cash Flows	101
Consolidated Statement of Partners’ Capital	102
Notes to Consolidated Financial Statements	103
1. Organization and Presentation	103
2. Summary of Significant Accounting Policies	104
3. Variable Interest Entities	113
4. Acquisitions	114
5. Fair Value Measurements	116
6. Inventories	118
7. Digital Assets	118
8. Property, Plant and Equipment	119
9. Long-Lived Asset Impairments	120
10. Investments	120
11. Leases	122
12. Long-Term Debt	123
13. Accrued Workers’ Compensation and Pneumoconiosis Benefits	126
14. Employee Benefit Plans	128
15. Asset Retirement Obligations	132
16. Commitments and Contingencies	133
17. Partners’ Capital	133
18. Common Unit-Based Compensation Plans	134
19. Revenue From Contracts With Customers	136
20. Concentration of Credit Risk and Major Customers	137
21. Related-Party Transactions	137
22. Income Taxes	139
23. Earnings Per Limited Partner Unit	141
24. Supplemental Cash Flow Information	142
25. Segment Information	142
26. Subsequent Event	145
Supplemental Oil & Gas Reserve Information (Unaudited)	146
Schedule I – Condensed Financial Information of Registrant	152
Item 9. Changes in and Disagreements with Accountant on Accounting and Financial Disclosure	154
Item 9A. Controls and Procedures	154
Item 9B. Other Information	157
PART III	
Item 10. Directors, Executive Officers and Corporate Governance of the General Partner	158
Item 11. Executive Compensation	165
Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters	179
Item 13. Certain Relationships and Related Transactions, and Director Independence	180
Item 14. Principal Accountant Fees and Services	182
PART IV	
Item 15. Exhibits and Financial Statement Schedules	183

GLOSSARY

The following are abbreviations and definitions of certain terms used in this document, some of which are defined by authoritative sources and others reflect those we commonly use in the coal and oil & gas industries:

<i>2029 Senior Notes</i>	An aggregate original principal amount of \$400.0 million of senior unsecured notes due 2029 issued on June 12, 2024 by the Intermediate Partnership and Alliance Finance.
<i>89 Energy</i>	89 Energy II Minerals, LLC
<i>A&D</i>	Acquisitions and Divestitures
<i>ACE Rule</i>	The Affordable Clean Energy Rule
<i>AGP</i>	Alliance GP, LLC, the parent company of ARLP's general partner
<i>AHGP</i>	Alliance Holdings GP, L.P., a wholly owned subsidiary of ARLP
<i>AllDale I</i>	AllDale Minerals, LP, an indirect wholly owned subsidiary of ARLP
<i>AllDale II</i>	AllDale Minerals II, LP, an indirect wholly owned subsidiary of ARLP
<i>AllDale III</i>	AllDale Minerals III, LP
<i>Alliance Coal</i>	Alliance Coal, LLC, an indirect wholly owned subsidiary of ARLP and the holding company for our coal mining operations
<i>Alliance Design</i>	Alliance Design Group, LLC, an indirect wholly owned subsidiary of ARLP
<i>Alliance Finance</i>	Alliance Resource Finance Corporation, an indirect wholly owned subsidiary of ARLP
<i>Alliance Minerals</i>	Alliance Minerals, LLC, an indirect wholly owned subsidiary of ARLP and the holding company for our oil & gas minerals interests
<i>Alliance Properties</i>	Alliance Properties, LLC, an indirect wholly owned subsidiary of ARLP
<i>Alliance Resource Properties</i>	Alliance Resource Properties, LLC, an indirect wholly owned subsidiary of ARLP and the holding company for our coal minerals interests
<i>Alliance WOR Properties</i>	Alliance WOR Properties, LLC, an indirect wholly owned subsidiary of ARLP
<i>Allocation Date</i>	That first day of each month in which we prorate our items of income, gain, loss and deduction between transferors and transferees of our units based upon the ownership of our units on that day.
<i>ARH</i>	Alliance Resource Holdings, Inc., a wholly owned subsidiary of ARLP
<i>ARLP</i>	Alliance Resource Partners, L.P., individually as the parent company, and not on a consolidated basis
<i>ARLP Partnership</i>	The business and operations of Alliance Resource Partners, L.P., the parent company, as well as its consolidated subsidiaries; references to "Partnership", "we", "us" or "our" also refer to the ARLP Partnership
<i>AROP II</i>	AROP II, LLC, an indirect wholly owned subsidiary of ARLP and the direct or indirect holding company for our other growth investments

<i>AROP Funding</i>	AROP Funding, LLC, an indirect wholly owned subsidiary of ARLP
<i>ASC</i>	Accounting Standards Codification
<i>Ascend</i>	Ascend Elements, Inc.
<i>ASI</i>	Alliance Service, Inc., an indirect wholly owned subsidiary of ARLP
<i>ASU</i>	Accounting Standards Update
<i>ASU 2023-09</i>	ASU 2023-09, <i>Income Taxes (Topic 740): Improvements to Income Tax Disclosures</i>
<i>ASU 2024-03</i>	ASU 2024-03, <i>Income Statement - Reporting Comprehensive Income - Expense Disaggregation Disclosures (Subtopic 220-40)</i>
<i>ASU 2025-06</i>	ASU 2025-06, <i>Intangibles - Goodwill and Other - Internal-Use Software (Subtopic 350-40): Targeted Improvements to the Accounting for Internal-Use Software</i>
<i>Audit Committee</i>	The audit committee of the Board of Directors
<i>Bankruptcy Code</i>	Title 11 of the United State Code
<i>Basin</i>	A geologic depression where sediments accumulate due to tectonics and subsidence. When rich hydrocarbon source rocks are present and conditions are suitable, a petroleum system may form, supporting oil & gas exploration and production.
<i>Basis differential</i>	The difference between the spot price of a commodity and the sales price at the delivery point where the commodity is sold
<i>Bbl</i>	Stock tank barrel, or 42 United States gallons liquid volume, used in reference to crude oil or other liquid hydrocarbons
<i>Bitiki</i>	Bitiki KY, LLC, an indirect wholly owned subsidiary of ARLP
<i>Bituminous coal</i>	Coal used primarily to generate electricity and to make coke for the steel industry with a heat value ranging between 10,500 and 15,500 Btus per pound.
<i>BLBA</i>	Federal Black Lung Benefits Act
<i>Bluegrass Minerals</i>	Bluegrass Minerals Management, LLC
<i>Board of Directors</i>	The board of directors of our general partner
<i>BOE</i>	Barrels of oil equivalent, with six Mcf of natural gas being equivalent to one Bbl of crude oil, condensate, or natural gas liquids
<i>BSER</i>	Best System of Emission Reduction
<i>Btu</i>	British thermal unit
<i>CAA</i>	Federal Clean Air Act
<i>Cavalier Minerals</i>	Cavalier Minerals JV, LLC, an indirect subsidiary of ARLP in which we hold the managing member interest and a 96% non-managing interest.
<i>CCR</i>	Coal combustion residuals

<i>CEO</i>	Chief Executive Officer
<i>CERCLA</i>	Federal Comprehensive Environmental Response, Compensation and Liability Act
<i>CFO</i>	Chief Financial Officer
<i>CGA</i>	Cawley, Gillespie & Associates, Inc.
<i>CODM</i>	Chief operating decision maker
<i>Compensation Committee</i>	The compensation committee of the Board of Directors
<i>Conflicts Committee</i>	The conflicts committee of the Board of Directors
<i>Continuous Miner</i>	An underground mining machine that cuts coal and loads it onto conveyors or into shuttle cars in a continuous operation.
<i>Corps of Engineers</i>	United States Army Corps of Engineers
<i>COSO</i>	Committee of Sponsoring Organizations of the Treadway Commission
<i>CPP</i>	Clean Power Plan
<i>Craft Foundations</i>	Collectively, The Joseph W. Craft III Foundation and The Kathleen S. Craft Foundation
<i>Credit Agreement</i>	The credit agreement entered into by Alliance Coal, as borrower, on January 13, 2023.
<i>CSX</i>	CSX Transportation, Inc.
<i>CTO</i>	Chief Technology Officer
<i>CWA</i>	Federal Clean Water Act
<i>D.C. Circuit Court</i>	United States Court of Appeals for the District of Columbia
<i>DERs</i>	Distribution equivalent rights
<i>Developed acreage</i>	Acreage allocated or assignable to productive wells.
<i>Directors' Deferred Compensation Plan</i>	Alliance Resource Management GP, L.P. Amended & Restated Deferred Compensation Plan for Directors
<i>DMP</i>	Division of Mine Permits
<i>DOL</i>	U.S. Department of Labor
<i>EGUs</i>	Electric generating units
<i>ELG</i>	Effluent Limitations Guidelines and Standards
<i>Elk Range Acquisition</i>	On October 31, 2025, we acquired approximately 190 oil & gas net royalty acres in the Midland and Delaware Basins from 89 Energy.
<i>Elk Range Acquisition Date</i>	October 31, 2025
<i>EPA</i>	United States Environmental Protection Agency

<i>EPU</i>	Earnings per limited partner unit
<i>ESA</i>	Endangered Species Act
<i>EV</i>	Electric vehicle
<i>Excel</i>	Excel Mining, LLC, an indirect wholly owned subsidiary of ARLP
<i>Exchange Act</i>	Securities Exchange Act of 1934
<i>FASB</i>	Financial Accounting Standards Board
<i>FIPs</i>	Federal Implementation Plans
<i>FMSHA</i>	Federal Mine Health and Safety Act of 1977, as amended by the Federal Mine Improvement and New Emergency Response Act of 2006
<i>Francis</i>	Francis Renewable Energy, LLC
<i>GAAP</i>	Generally Accepted Accounting Principles
<i>Gavin Generation</i>	Gavin Generation Holdings A, LP
<i>GHG</i>	Greenhouse gas
<i>Gibson</i>	Gibson County Coal, LLC, an indirect wholly owned subsidiary of ARLP
<i>Gibson South</i>	Gibson County Coal (South), LLC, an indirect wholly owned subsidiary of ARLP
<i>Grant Thornton</i>	Grant Thornton LLP
<i>Gross acres</i>	The total acres in a specified tract in which an owner has a real property interest. For example, an owner who has a 25 percent interest in 100 acres has an ownership interest in 100 gross acres.
<i>Hamilton</i>	Hamilton County Coal, LLC, an indirect wholly owned subsidiary of ARLP
<i>Haymaker</i>	Haymaker Minerals & Royalties II, LLC
<i>High-sulfur coal</i>	Based on market expectations, our classification of coal with a sulfur content of greater than 3%
<i>HLBV</i>	Hypothetical liquidation at book value
<i>Indicated mineral resource (coal)</i>	That part of a mineral resource for which quantity and grade or quality are estimated on the basis of adequate geological evidence and sampling. The level of geological certainty associated with an indicated mineral resource is sufficient to allow a qualified person to apply modifying factors in sufficient detail to support mine planning and evaluation of the economic viability of the deposit. Because an indicated mineral resource has a lower level of confidence than the level of confidence of a measured mineral resource, an indicated mineral resource may only be converted to a probable mineral reserve.
<i>Inferred mineral resource (coal)</i>	That part of a mineral resource for which quantity and grade or quality are estimated on the basis of limited geological evidence and sampling. The level of geological uncertainty associated with an inferred mineral resource is too high to apply relevant technical and economic factors likely to influence the prospects of economic extraction in a manner

useful for evaluation of economic viability. Because an inferred mineral resource has the lowest level of geological confidence of all mineral resources, which prevents the application of the modifying factors in a manner useful for evaluation of economic viability, an inferred mineral resource may not be considered when assessing the economic viability of a mining project, and may not be converted to a mineral reserve.

<i>Infinitum</i>	Infinitum Electric, Inc.
<i>Intermediate Partnership</i>	Alliance Resource Operating Partners, L.P., the indirect wholly owned intermediate partnership of Alliance Resource Partners, L.P.
<i>IRAs</i>	Individual retirement accounts
<i>IRS</i>	Internal Revenue Service
<i>Island Creek</i>	Island Creek Coal Company
<i>JC Land</i>	JC Land LLC
<i>JC Resources</i>	JC Resources LP
<i>JC Resources Acquisition</i>	On February 22, 2023, we acquired 2,682 oil & gas net royalty acres in the Delaware Basin from JC Resources LP.
<i>KYDNR</i>	Kentucky Department of Natural Resources
<i>Long-term contracts</i>	Contracts having a term of one year or greater
<i>Longwall mining</i>	An underground coal mining method that removes nearly all of a coal seam over a very large area using specialized equipment.
<i>Low-sulfur coal</i>	Based on market expectations, we classify coal with a sulfur content of less than 1.5%
<i>LTIP</i>	Amended and Restated Alliance Coal, LLC 2000 Long-Term Incentive Plan
<i>Matrix Design</i>	Matrix Design Group, LLC, an indirect wholly owned subsidiary of ARLP
<i>Matrix Group</i>	Collectively our subsidiaries, Alliance Design, ASI and its subsidiary, Matrix Design and its subsidiaries Matrix Design International, LLC, Matrix Design Africa (PTY) LTD, and Matrix Design (Australia) PTY, LTD
<i>MATS</i>	Mercury and Air Toxics Standards
<i>MBbls</i>	Thousand barrels of crude oil or other liquid hydrocarbons
<i>MBOE</i>	One thousand barrels of crude oil equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate, or natural gas liquids
<i>MC Mining</i>	MC Mining, LLC, an indirect wholly owned subsidiary of ARLP
<i>Mcf</i>	Thousand cubic feet of natural gas
<i>Measured mineral resource (coal)</i>	That part of a mineral resource for which quantity and grade or quality are estimated on the basis of conclusive geological evidence and sampling. The level of geological certainty associated with a measured mineral resource is sufficient to allow a qualified person to apply modifying factors, as defined in this section, in sufficient detail to support detailed mine planning and final evaluation of the economic viability of the deposit. Because a

	measured mineral resource has a higher level of confidence than the level of confidence of either an indicated mineral resource or an inferred mineral resource, a measured mineral resource may be converted to a proven mineral reserve or to a probable mineral reserve.
<i>Medium-sulfur coal</i>	Based on market expectations, our classification of coal with a sulfur content of 1.5% to 3%
<i>Metallurgical coal</i>	Coal primarily used in the production of steel
<i>Mettiki</i>	Mettiki Complex, including the Mountain View mine operated by Mettiki (WV) and the preparation plant operated by Mettiki (MD)
<i>Mettiki (MD)</i>	Mettiki Coal, LLC, an indirect wholly owned subsidiary of ARLP
<i>Mettiki (WV)</i>	Mettiki Coal (WV), LLC, an indirect wholly owned subsidiary of ARLP
<i>MGP</i>	Alliance Resource Management GP, LLC, ARLP's general partner
<i>MINER Act</i>	Federal Mine Improvement and New Emergency Response Act of 2006
<i>Mineral interest</i>	Mineral interests are real property interests that are typically perpetual and grant ownership to the oil & gas under a tract of land or the rights to explore for, develop, and produce oil & gas on that land or to lease those exploration and development rights to a third party.
<i>Mineral reserve (coal)</i>	An estimate of tonnage and grade or quality of indicated and measured mineral resources that, in the opinion of the qualified person, can be the basis of an economically viable project. More specifically, it is the economically mineable part of a measured or indicated mineral resource, which includes diluting materials and allowances for losses that may occur when the material is mined or extracted.
<i>Mineral resource (coal)</i>	A concentration or occurrence of material of economic interest in or on the Earth's crust in such form, grade or quality, and quantity that there are reasonable prospects for economic extraction. A mineral resource is a reasonable estimate of mineralization, taking into account relevant factors such as cut-off grade, likely mining dimensions, location or continuity that, with the assumed and justifiable technical and economic conditions, is likely to, in whole or in part, become economically extractable. It is not merely an inventory of all mineralization drilled or sampled.
<i>MMBtus</i>	Million British thermal units
<i>MMcf</i>	Million cubic feet of natural gas
<i>Mr. Craft</i>	Joseph W. Craft III, the Chairman, President and Chief Executive Officer of MGP
<i>MSHA</i>	Mine Safety and Health Administration
<i>Mt. Vernon</i>	Mt. Vernon Transfer Terminal, LLC, an indirect wholly owned subsidiary of ARLP
<i>NAAQS</i>	National Ambient Air Quality Standards
<i>Named Executive Officers</i>	Our Chairman, President and CEO (our principal executive officer), the Senior Vice President and Chief Financial Officer (our principal financial officer) and the three most highly compensated executive officers.
<i>NEPA</i>	National Environmental Policy Act

<i>Net mineral acres</i>	The actual ownership interest within a specified tract expressed in acres. For example, an owner who has a 50 percent interest in 100 acres owns 50 net mineral acres.
<i>Net royalty acres</i>	Mineral ownership standardized to a 12.5%, or 1/8 th , royalty interest. For example, 200 net royalty interest would be the equivalent of 100 net mineral acres. ($100 \times 0.25/0.125 = 200$)
<i>NGLs</i>	Natural gas liquids are components of natural gas that are liquid at the surface in field facilities or gas-processing plants. Natural gas liquids can be classified according to their vapor pressures as low (condensate), intermediate (natural gasoline), and high (liquefied petroleum gas) vapor pressure. Natural gas liquids include propane, butane, pentane, hexane, and heptane, but not methane and ethane since these hydrocarbons need refrigeration to be liquefied. The term is commonly abbreviated as NGL.
<i>NGP</i>	NGP Energy Capital Management, LLC
<i>NGP ET IV</i>	NGP Energy Transition IV, L.P.
<i>NMFS</i>	National Marine Fisheries Service
<i>NS</i>	Norfolk Southern Railway Company
<i>NSPS</i>	New Source Performance Standards
<i>NSR</i>	New source review
<i>Oil & gas</i>	Crude oil, natural gas, and natural gas liquids
<i>Old Ben</i>	Old Ben Coal Company
<i>OSM</i>	Federal Office of Surface Mining
<i>OWCP</i>	Office of Workers' Compensation Programs
<i>PADEP</i>	Pennsylvania Department of Environmental Protection
<i>PAL</i>	Paducah & Louisville Railway, Inc.
<i>Patriot</i>	Patriot Coal Corporation
<i>PCAOB</i>	Public Company Accounting Oversight Board
<i>Peabody</i>	Peabody Energy Corporation
<i>Pension Plan</i>	Alliance Coal, LLC and Affiliates Pension Plan for Coal Employees
<i>PM</i>	Fine particulate matter
<i>Preparation plant</i>	A facility used for crushing, sizing, and washing coal to remove impurities and to prepare it for use by a particular customer.
<i>Probable mineral reserve (coal)</i>	The economically mineable part of an indicated and, in some cases, a measured mineral resource.
<i>Productive well</i>	A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

<i>Proved developed reserves (oil & gas)</i>	Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
<i>Proved reserves or properties (oil & gas)</i>	Proved reserves are those quantities of oil & gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.
<i>Proved undeveloped reserves (oil & gas)</i>	Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.
<i>Proven mineral reserve (coal)</i>	The economically mineable part of a measured mineral resource and can only result from conversion of a measured mineral resource.
<i>PSSP</i>	Profit sharing and savings plan
<i>PUDs</i>	Proved undeveloped reserves
<i>RCRA</i>	Federal Resource Conservation and Recovery Act
<i>Reclamation</i>	The restoration of land and environmental standards to a mining site after the coal is extracted, including returning the land to its approximate original appearance, restoring topsoil, and planting native grass and ground covers.
<i>Reserves (oil & gas)</i>	Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to the market, and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible.
<i>RESPEC</i>	RESPEC Company, LLC
<i>Revolving Credit Facility</i>	The Credit Agreement provides for a \$425.0 million revolving credit facility, which includes a sublimit of \$15.0 million for swingline borrowings and permits the issuance of letters of credit up to the full amount of \$425.0 million.
<i>RGGI</i>	Regional Greenhouse Gas Initiative agreement
<i>River View</i>	River View Coal, LLC, an indirect wholly owned subsidiary of ARLP
<i>Room-and-pillar mining</i>	An underground coal mining method that creates a network of “rooms” in a coal seam while leaving behind “pillars” of coal to support the roof of a mine.
<i>Royalty interest</i>	An interest that gives the owner the right to receive a portion of the resources or revenues without having to carry any costs of development or operations.

<i>Schnitzer Employment Letter</i>	An employment letter we provided to our Senior Vice President, General Counsel and Secretary, Mr. Schnitzer, in connection with his hiring in March 2024 setting forth the terms of his employment.
<i>SDWA</i>	Federal Safe Drinking Water Act
<i>Sebree</i>	Sebree Mining, LLC, an indirect wholly owned subsidiary of ARLP
<i>SEC</i>	United States Securities and Exchange Commission
<i>Securities Act</i>	Securities Act of 1933
<i>Securitization Facility</i>	Certain direct and indirect wholly owned subsidiaries of our Intermediate Partnership are party to an accounts receivable securitization facility
<i>SERP</i>	Alliance Coal, LLC Supplemental Executive Retirement Plan
<i>SIPs</i>	State implementation plans
<i>Skyland</i>	Skyland Minerals, L.P.
<i>Skyland Acquisition</i>	On December 7, 2023, we acquired 2,372 oil & gas net royalty acres predominantly in the Anadarko Basin, along with acreage in the Williston and Delaware Basins from Skyland Minerals, L.P. and Haymaker Minerals & Royalties II, LLC.
<i>Skyland Acquisition Date</i>	December 7, 2023
<i>SMCRA</i>	Federal Surface Mining Control and Reclamation Act of 1977
<i>STIP</i>	Alliance Resource Management GP, LLC Short-Term Incentive Plan
<i>Subsidiary Guarantors</i>	Certain subsidiaries of ARLP, including the Intermediate Partnership and most of the direct and indirect subsidiaries of Alliance Coal, guaranteeing the Credit Agreement.
<i>Term Loan</i>	The Credit Agreement provides for a term loan in an aggregate principal amount of \$75.0 million.
<i>Thermal coal</i>	Coal used primarily in the generation of electricity
<i>TMDL</i>	Total Maximum Daily Load
<i>TRRC</i>	Texas Railroad Commission
<i>TRS</i>	Technical Report Summary
<i>Tunnel Ridge</i>	Tunnel Ridge, LLC, an indirect wholly owned subsidiary of ARLP
<i>UIC</i>	Underground Injection Control
<i>Undeveloped acreage (oil & gas)</i>	Acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil & gas regardless of whether such acreage contains proved reserves.
<i>Unproved reserves or properties (oil & gas)</i>	Properties with no proved reserves. We also consider unproved reserves or properties to be defined as the estimated quantities of oil & gas determined based on geological and engineering data similar to that used in estimates of proved reserves; but technical,

contractual, economic, or regulatory uncertainties preclude such reserves from being classified as proved.

<i>U.S. or United States</i>	The United States of America
<i>USFWS</i>	United States Fish and Wildlife Service
<i>Valley Camp</i>	Valley Camp Coal Company
<i>VIE</i>	Variable interest entity
<i>VOC</i>	Volatile organic compound
<i>Warrior</i>	Warrior Coal, LLC, an indirect wholly owned subsidiary of ARLP
<i>Webster</i>	Webster County Coal, LLC, an indirect wholly owned subsidiary of ARLP
<i>Wildcat Insurance</i>	Wildcat Insurance, LLC, an indirect wholly owned subsidiary of ARLP
<i>WKY CoalPlay</i>	WKY CoalPlay, LLC, an entity owned by the Craft Foundations and two limited liability companies owned by irrevocable trusts established by Mr. Craft and his children
<i>WKY11</i>	West Kentucky No. 11
<i>WKY6</i>	West Kentucky No. 6
<i>WKY7</i>	West Kentucky No. 7
<i>WKY9</i>	West Kentucky No. 9
<i>WOTUS</i>	Waters of the United States
<i>WVDEP</i>	West Virginia Department of Environmental Protection

FORWARD-LOOKING STATEMENTS

Certain statements and information in this Annual Report on Form 10-K, and certain oral statements made from time to time by our representatives, constitute “forward-looking statements.” These statements are based on our beliefs as well as assumptions made by, and information currently available to, us. When used in this document, the words “anticipate,” “believe,” “continue,” “could,” “estimate,” “expect,” “forecast,” “foresee,” “may,” “outlook,” “plan,” “project,” “potential,” “should,” “will,” “would,” and similar expressions identify forward-looking statements. Without limiting the foregoing, all statements relating to our future outlook, anticipated capital expenditures, future cash flows and borrowings, and sources of funding are forward-looking statements. These forward-looking statements are based on our current expectations and beliefs concerning future developments and reflect our current views with respect to future events and are subject to numerous assumptions that we believe are reasonable, but are open to a wide range of uncertainties and business risks, and actual results could differ materially from those discussed in these statements. Among the factors that could cause actual results to differ from those in the forward-looking statements are:

- decline in the coal industry’s share of electricity generation, including as a result of environmental concerns related to coal mining and combustion, the cost and perceived benefits of other sources of electricity and fuels, such as oil & gas, nuclear energy, and renewable fuels and the retirement of coal-fired power plants in the U.S.;
- our ability to provide fuel for growth in domestic energy demand, should it materialize;
- changes in macroeconomic and market conditions and market volatility, and the impact of such changes and volatility on our financial position;
- changes in global economic and geo-political conditions or changes in industries in which our customers operate;
- changes in commodity prices, demand and availability which could affect our operating results and cash flows;
- the effects of a prolonged government shutdown;
- impacts of geopolitical events, including the conflicts in Ukraine, hostilities in the Middle East and the evolving situation in Venezuela;
- the severity, magnitude and duration of any future pandemics and impacts of such pandemics and of businesses’ and governments’ responses to such pandemics on our operations and personnel, and on demand for coal, oil, and natural gas, the financial condition of our customers and suppliers and operators, available liquidity and capital sources and broader economic disruptions;
- actions of the major oil-producing countries with respect to oil production volumes and prices and the direct and indirect impacts over the near and long term on oil & gas exploration and production operations at the properties in which we hold mineral interests;
- changes in competition in domestic and international coal markets and our ability to respond to such changes;
- potential shut-ins of production by the operators of the properties in which we hold oil & gas mineral interests due to low commodity prices or the lack of downstream demand or storage capacity;
- risks associated with the expansion of and investments into the infrastructure of our operations and properties, including the timing of such investments coming online;
- our ability to identify and complete acquisitions and to successfully integrate such acquisitions into our business and achieve the anticipated benefits therefrom;
- our ability to identify and invest in new energy and infrastructure transition ventures;
- the success of our development and growth plans for our subsidiary Matrix Design and our investments in emerging and other infrastructure and technology companies;
- dependence on significant customer contracts, and failure of customers to renew existing contracts upon expiration;
- adjustments made in price, volume, or terms to existing coal supply agreements;
- the effects of and changes in trade, monetary and fiscal policies and laws, and the results of central bank policy actions including interest rates, bank failures, and associated liquidity risks;
- the effects of and changes in taxes or tariffs and other trade measures adopted or threatened by the United States and foreign governments, including the imposition of or increase in tariffs on steel and/or other raw materials;
- legislation, regulations, and court decisions and interpretations thereof, both domestic and foreign, including those relating to the environment and the release of greenhouse gases, such as state legislation seeking to

impose liability on a wide range of energy companies under greenhouse gas “superfund” laws, mining, miner health and safety, hydraulic fracturing, and health care;

- deregulation of the electric utility industry or the effects of any adverse change in the coal industry, electric utility industry, or general economic conditions;
- investors’ and other stakeholders’ attention to sustainability matters;
- liquidity constraints, including those resulting from any future unavailability of financing;
- customer bankruptcies, cancellations or breaches to existing contracts, or other failures to perform;
- customer delays, failure to take coal under contracts or defaults in making payments;
- our productivity levels and margins earned on our coal sales;
- disruptions to oil & gas exploration and production operations at the properties in which we hold mineral interests;
- changes in equipment, raw material, service or labor costs or availability, including due to inflationary pressures or tariffs;
- changes in our ability to recruit, hire and maintain labor;
- our ability to maintain satisfactory relations with our employees;
- increases in labor costs, including increases in the costs of health insurance, adverse changes in work rules, or cash payments or projections associated with workers’ compensation claims;
- increases in transportation costs and risk of transportation delays or interruptions;
- operational interruptions due to geologic, permitting, labor, weather, supply chain shortage of equipment or mine supplies, or other factors;
- risks associated with major mine-related accidents, mine fires, mine floods, or other interruptions;
- results of litigation, including claims not yet asserted;
- foreign currency fluctuations that could adversely affect the competitiveness of our coal abroad;
- difficulty maintaining our surety bonds for mine reclamation as well as workers’ compensation and black lung benefits;
- difficulty in making accurate assumptions and projections regarding post-mine reclamation as well as pension, black lung benefits, and other post-retirement benefit liabilities;
- uncertainties in estimating and replacing our coal mineral reserves and resources;
- uncertainties in estimating and replacing our oil & gas reserves;
- uncertainties in the amount of oil & gas production due to the level of drilling and completion activity by the operators of our oil & gas properties;
- the impact of current and potential changes to federal or state tax rules and regulations, including a loss or reduction of benefits from certain tax deductions and credits;
- difficulty obtaining commercial property insurance, and risks associated with our participation in the commercial insurance property program;
- evolving cybersecurity risks, such as those involving unauthorized access, denial-of-service attacks, malicious software, data privacy breaches by employees, insiders or others with authorized access, cyber- or phishing attacks, ransomware, malware, social engineering, physical breaches, or other actions;
- difficulty in making accurate assumptions and projections regarding future revenues and costs associated with equity investments in companies we do not control; and
- other factors, including those discussed in “Item 1A. Risk Factors” and “Item 3. Legal Proceedings.”

If one or more of these or other risks or uncertainties materialize, or should our underlying assumptions prove incorrect, our actual results could differ materially from those described in any forward-looking statement. When considering forward-looking statements, you should also keep in mind our risk factors and legal proceedings. Known material factors that could cause our actual results to differ from those in the forward-looking statements are described in “Item 1A. Risk Factors” and “Item 3. Legal Proceedings.” We disclaim any obligation to update or revise any forward-looking statements or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments unless required by law.

You should consider the information above when reading any forward-looking statements contained in this Annual Report on Form 10-K; other reports filed by us with the SEC; our press releases; our website www.arlp.com; and written or oral statements made by us or any of our officers or other authorized persons acting on our behalf.

PART I

ITEM 1. BUSINESS

Introduction

We are a diversified natural resource company that generates operating and royalty income from the production and marketing of coal to major domestic utilities, industrial users and international customers, as well as royalty income from oil & gas mineral interests located in key producing regions across the United States. Our core objective is to maximize the value of our mineral asset base—both through coal production from our mining operations and through the leasing and development of our coal and oil & gas mineral interests. Our strategy is to provide reliable, baseload fuel for electricity generating customers while positioning the Partnership for long-term growth through investments in energy and related infrastructure. Leveraging our relationships with electric utilities, industrial customers, and government partners, we intend to pursue strategic opportunities that complement our operational strengths. We believe our diverse resource portfolio and targeted investments will continue to create long-term value for our unitholders.

We are the second largest coal producer in the eastern United States and as of December 31, 2025, we operated seven underground mining complexes across Illinois, Indiana, Kentucky, Maryland, Pennsylvania, and West Virginia and a coal-loading terminal on the Ohio River in Indiana. We manage and report our coal operations under two regions, Illinois Basin and Appalachia. We market our coal production to major domestic and international utilities and industrial customers.

We also own mineral and royalty interests in approximately 70,000 net royalty acres, including approximately 4,000 net royalty acres attributable to our equity interest in AllDale III, in premier oil & gas producing regions in the United States, primarily the Permian, Anadarko, and Williston Basins. While we own both oil & gas mineral and royalty interests, we refer to them collectively as mineral interests throughout our discussions of our business as the majority of our holdings are mineral interests. We market our oil & gas mineral interests for lease to operators in those regions and generate royalty income from their development of those mineral interests. We expect reserve additions and the related cash flows to grow through further development of our existing mineral interests as well as acquisitions of additional mineral interests.

We also hold coal mineral reserves and resources in Illinois, Indiana, Kentucky, Pennsylvania and West Virginia. Substantially all of our coal mineral resources and a majority of our coal mineral reserves are owned or leased by Alliance Resource Properties, which are (a) leased or subleased to our mining complexes or (b) near other internal and external coal mining operations but not yet leased. We generate intercompany royalty income through the leasing and development of our coal mineral reserves and resources.

Beyond our core mineral platform, we have invested in growth-oriented businesses and energy-related technologies. Our subsidiary, Matrix Group, develops and markets industrial, mining and technology products and services worldwide and our subsidiary, Bitiki, mines bitcoin. We have also made investments in emerging energy and infrastructure opportunities, including Infinitem, NGP ET IV and Gavin Generation.

ARLP, a Delaware limited partnership, completed its initial public offering on August 19, 1999, and is listed on the NASDAQ Global Select Market under the ticker symbol “ARLP.” We are managed by our sole general partner, MGP, a Delaware limited liability company, which holds a non-economic general partner interest in ARLP.

Oil & Gas Acquisitions

Elk Range

On October 31, 2025, we acquired approximately 190 oil & gas net royalty acres in the Midland and Delaware Basins from 89 Energy for a purchase price of \$10.0 million. This acquisition enhances our ownership position in the Permian Basin and furthers our business strategy to grow our Oil & Gas Royalties segment. For more information on this acquisition please read “Item 8. Financial Statements and Supplementary Data—Note 4 - Acquisitions” of the Annual Report on Form 10-K.

Other Growth Investments

The following investments in growth-oriented businesses and energy related technologies further our business strategy to develop strategic relationships and invest in strategic opportunities that leverage our core competencies and build platforms for future lines of business with long-term growth and cash flow generation. For more information on our investments, please read “Item 8. Financial Statements and Supplementary Data—Note 3 – Variable Interest Entities” and “—Note 10 – Investments” of the Annual Report on Form 10-K.

Infinitum

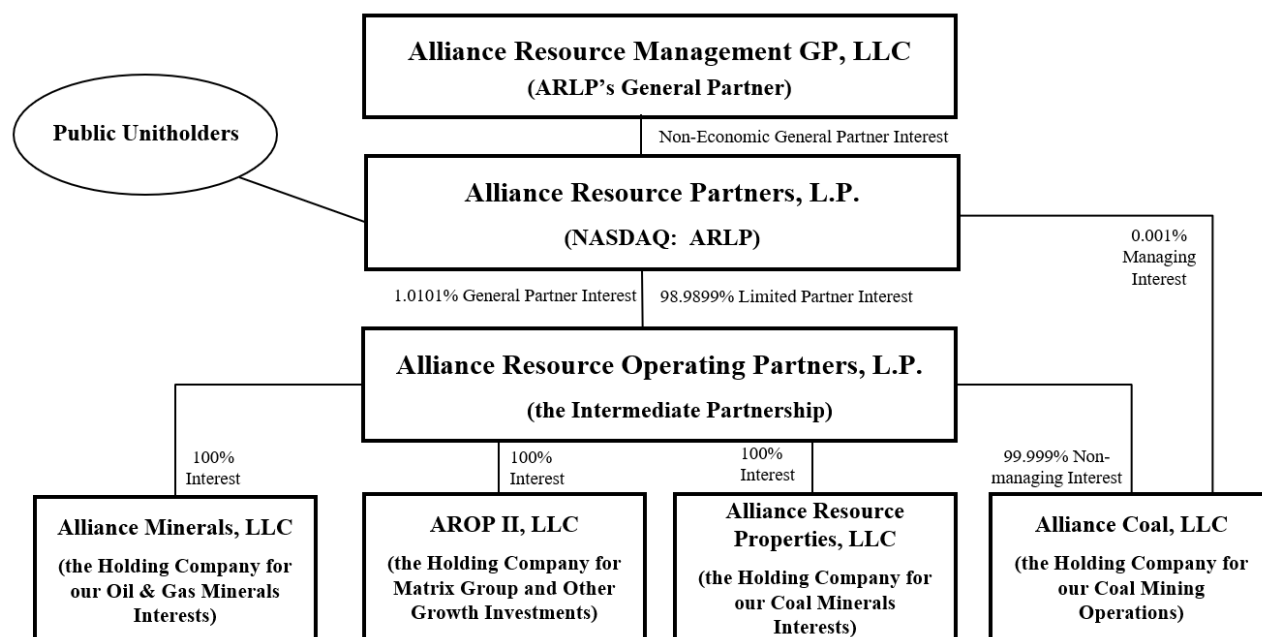
On December 31, 2025, we increased our investment in Infinitum to \$82.5 million by purchasing \$14.9 million of Series F Preferred Stock. Infinitum is a Texas-based startup developer and manufacturer of electric motors featuring printed circuit board stators that have the potential to result in motors that are smaller, lighter, quieter, more efficient and capable of operating at a fraction of the carbon footprint of conventional electric motors.

Gavin Generation

In February 2025, we committed to invest up to \$25 million in limited partner interests in Gavin Generation. As of December 31, 2025, we have funded \$17.3 million of this commitment after giving effect to returns on our investment. Gavin Generation owns, indirectly, an interest in a joint venture holding company formed with a third party that indirectly owns and operates a coal-fired power plant.

Structure

The following diagram depicts our simplified organization and ownership as of December 31, 2025 and does not include each of our subsidiaries. See Exhibit 21.1 to this Annual Report on Form 10-K for a listing of our subsidiaries.



Available Information

Our internet address is www.arlp.com, and we make available free of charge on our website our Annual Reports on Form 10-K, our Quarterly Reports on Form 10-Q, our Current Reports on Form 8-K, Forms 3, 4 and 5 for our Section 16 filers and other documents (and amendments and exhibits, such as press releases, to such filings) as soon as reasonably practicable after we electronically file with or furnish such material to the SEC. Information on our website or any other website is not incorporated by reference into this report and does not constitute a part of this report.

The SEC maintains a website that contains reports, proxy and information statements, and other information for issuers, including us. The public can obtain any documents that we file with the SEC at www.sec.gov.

Coal Mining Operations

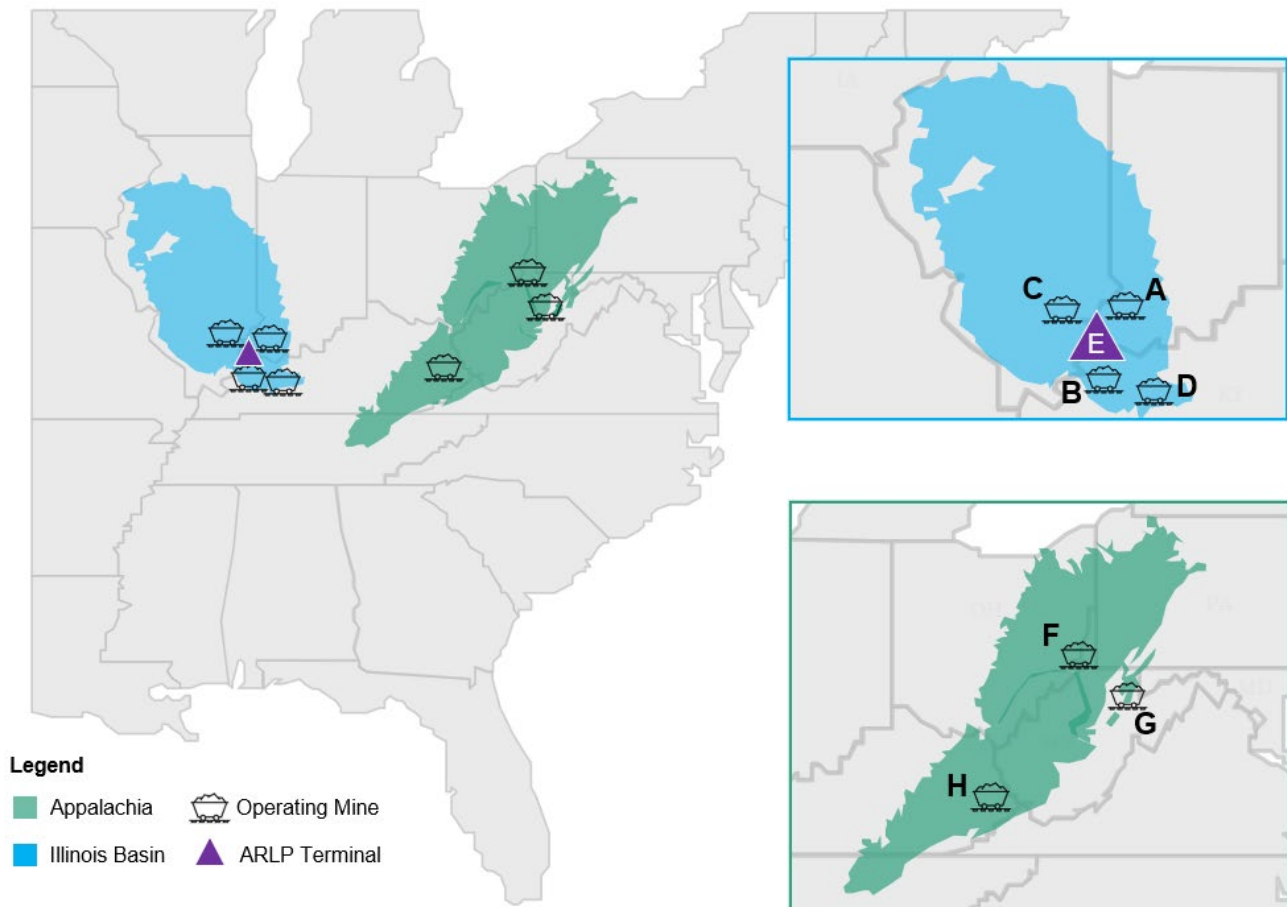
Coal remains an essential fuel source for electric power generation and a critical input for steel production, with additional uses in chemical, food, and cement processing. Our operations produce bituminous coal from underground mines, which we sell primarily into the thermal and metallurgical markets. We have established and maintained long-term relationships with customers through consistent delivery performance and reliable contract fulfillment.

At December 31, 2025, our mining operations, which are held by Alliance Coal, had access to approximately 586.3 million tons of coal mineral reserves and 1.07 billion tons of coal mineral resources in Illinois, Indiana, Kentucky, Maryland, Pennsylvania, and West Virginia. Substantially, all of our coal mineral resources and 509.6 million tons of our coal mineral reserves are owned or leased by Alliance Resource Properties and are currently leased or subleased or held for lease or sublease to our mining operations or others. We produce a diverse range of thermal and metallurgical coal with varying sulfur and heat contents, enabling us to meet a broad range of customer specifications. In 2025, we sold 33.0 million tons of coal and produced 33.2 million tons. Of the 33.0 million tons sold, 73% were leased from Alliance Resource Properties. The coal we sold in 2025 was approximately 18.7% low-sulfur coal, 51.8% medium-sulfur coal, and 29.5% high-sulfur coal. Demand for our coal remained concentrated in the domestic power sector, where 89.2% of our 2025 tons sold were purchased by domestic electric utilities and 8.6% were sold into the international markets through brokered transactions. The balance of our tons sold was to third-party resellers and industrial consumers domestically. For tons sold to domestic electric utilities, 100% were sold to utility plants with installed pollution control devices. The Btu content of our coal ranges from 11,400 to 13,200, positioning our products to meet customer requirements across multiple end-use applications.

The following chart summarizes our coal production by region for the last three years.

<u>Coal Regions</u>	<u>Year Ended December 31,</u>		
	<u>2025</u>	<u>2024</u>	<u>2023</u>
	(tons in millions)		
Illinois Basin	26.1	24.2	25.2
Appalachia	7.1	8.0	9.7
Total	<u>33.2</u>	<u>32.2</u>	<u>34.9</u>

The following map shows the location of our coal mining operations:



Illinois Basin Operations:

A. GIBSON COMPLEX

Gibson South Mine
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Room-and-Pillar
Coal Type: Low/Medium-Sulfur
Transportation: Barge, Railroad & Truck

B. RIVER VIEW COMPLEX

a) River View Mine
b) Henderson County Mine
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Room-and-Pillar
Coal Type: Medium/High-Sulfur
Transportation: Barge & Truck

C. HAMILTON COMPLEX

Hamilton Mine
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Longwall & Continuous Miner
Coal Type: Medium/High-Sulfur
Transportation: Barge, Railroad & Truck

D. WARRIOR COMPLEX

Warrior Mine
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Room-and-Pillar
Coal Type: Medium/High-Sulfur
Transportation: Barge, Railroad, & Truck

E. MOUNT VERNON

TRANSFER TERMINAL
Rail or Truck to Ohio River Barge
Transloading Facility

Appalachian Operations:

F. TUNNEL RIDGE COMPLEX

Tunnel Ridge Mine
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Longwall & Continuous Miner
Coal Type: Medium/High-Sulfur
Transportation: Barge

G. METTIKI COMPLEX

Mountain View Mine
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Longwall & Continuous Miner
Coal Type: Low/Medium Sulfur - Metallurgical
Transportation: Railroad & Truck

H. MC MINING COMPLEX

Excel Mine No. 5
Mining Type: Underground
Mining Access: Slope & Shaft
Mining Method: Room-and-Pillar
Coal Type: Low-Sulfur
Transportation: Barge, Railroad, & Truck

We lease most of our coal mineral reserves and resources from Alliance Resource Properties or private parties and generally have the right to maintain leases in force until the exhaustion of mineable and merchantable coal located within the leased premises or a larger coal mineral reserve or resource area. These leases provide for royalties to be paid to the lessors at a fixed amount per ton or as a percentage of the sales price. Many leases require payment of minimum royalties, payable either at the time of the execution of the lease or in periodic installments, even if no mining activities have begun. These minimum royalties are normally credited against the production royalties owed to a lessor once coal production has commenced.

Illinois Basin Operations

Our Illinois Basin mining operations are located in western Kentucky, southern Illinois, and southern Indiana. As of December 31, 2025, we had 2,013 employees and we operated four mining complexes in the Illinois Basin. Production from these operations supplies a diverse group of domestic utilities and industrial customers, supported by multiple rail, truck, and barge transportation options.

Gibson Complex

Gibson operates the Gibson South mine, located near the city of Princeton in Gibson County, Indiana. The Gibson South mine is an underground mine and utilizes continuous mining units employing room-and-pillar mining techniques to produce low/medium-sulfur coal. The preparation plant has throughput capacity of 1,800 tons of raw coal per hour. Production from the Gibson South mine is shipped by truck or transported by rail on the CSX or NS railroads from our rail loadout facility directly to customers or various transloading facilities, including our Mt. Vernon transloading facility, for barge delivery. Production from the mine began in April 2014. Gibson coal production in 2025 was 5.5 million tons.

River View Complex

River View operates the River View mine located near Uniontown in Union County, Kentucky and the Henderson County mine located near Corydon in Henderson County, Kentucky. The River View mine began production in 2009 and utilizes continuous mining units to produce medium/high-sulfur coal. The Henderson County mine began full production in 2024 and utilizes continuous mining units to produce medium/high-sulfur coal.

Both mines utilize the existing preparation plant, refuse disposal, and loadout facilities. The preparation plant has throughput capacity of 2,700 tons of raw coal per hour. Coal produced from the River View complex is transported by overland belt to a barge loading facility on the Ohio River. River View complex coal production in 2025 was 9.6 million tons.

Hamilton Complex

Hamilton operates the Hamilton mine, located near the city of McLeansboro in Hamilton County, Illinois. The Hamilton mine is an underground longwall mining operation producing medium/high-sulfur coal. Longwall mining began in October 2014 and we acquired complete ownership and control in 2015. The preparation plant has throughput capacity of 2,000 tons of raw coal per hour. Hamilton's production is shipped via the CSX, Evansville Western Railway, or NS rail directly to customers or various transloading facilities, including our Mt. Vernon transloading facility, for barge deliveries. Hamilton coal production in 2025 was 6.5 million tons.

Warrior Complex

Warrior operates an underground mining complex located near the city of Madisonville in Hopkins County, Kentucky. The Warrior complex was opened in 1985, and we acquired it in February 2003. Warrior utilizes continuous mining units employing room-and-pillar mining techniques to produce medium/high-sulfur coal. The preparation plant has throughput capacity of 1,200 tons of raw coal per hour. Warrior's production is shipped via the CSX or PAL railroads or by truck directly to customers or potentially to various transloading facilities, including our Mt. Vernon transloading facility, for barge deliveries. Warrior coal production in 2025 was 4.5 million tons.

Mt. Vernon Transfer Terminal, LLC

Mt. Vernon leases land and operates a coal-loading terminal on the Ohio River at Mt. Vernon in Posey County, Indiana. Coal is delivered to Mt. Vernon by both rail and truck. The terminal has a capacity of 8.0 million tons per year with existing ground storage of approximately 200,000 tons. In 2025, the terminal loaded approximately 1.6 million tons for customers of Gibson and Hamilton.

Appalachian Operations

Our Appalachian mining operations are located in eastern Kentucky, western Maryland, western Pennsylvania, and northern West Virginia. As of December 31, 2025, we had 882 employees and we operated three mining complexes in Appalachia. Production from these operations supply both thermal and metallurgical markets and benefit from access to barge and rail networks serving domestic and international customers.

Tunnel Ridge Complex

Tunnel Ridge operates the Tunnel Ridge mine, an underground longwall mine located near the city of Wheeling in Ohio County, West Virginia. Longwall mining operations began at Tunnel Ridge in May 2012. The preparation plant has throughput capacity of 2,000 tons of raw coal per hour. Coal produced from the Tunnel Ridge mine is medium/high-sulfur coal and is transported by conveyor belt to a barge loading facility on the Ohio River. Tunnel Ridge also has the ability through a third-party facility to transload coal from barges for rail shipment on the Wheeling and Lake Erie Railway with connections to the CSX and the NS railroads. Tunnel Ridge coal production in 2025 was 5.2 million tons.

Mettiki Complex

Mettiki operates the Mountain View mine located in Tucker County, West Virginia and a preparation plant located near the city of Oakland in Garrett County, Maryland. Mettiki (WV) began longwall mining in November 2006. The Mountain View mine produces low/medium-sulfur coal, which is transported by truck to the Mettiki (MD) preparation plant for processing for shipment into the metallurgical or thermal coal markets. The preparation plant has throughput capacity of 1,350 tons of raw coal per hour. Coal processed at the preparation plant can be trucked to the blending facility at the Virginia Electric and Power Company, Mt. Storm Power Station, or shipped via the CSX railroad, which provides the opportunity to ship into the domestic and international metallurgical and thermal coal markets. Mettiki (WV) coal production in 2025 was 1.2 million tons.

On January 29, 2026, the decision was made to cease longwall production and primarily satisfy remaining contractual commitments from existing inventory. We will continue to evaluate options concerning the mine's future.

MC Mining Complex

MC Mining is located near the city of Pikeville in Pike County, Kentucky. MC Mining operates the Excel Mine No. 5. We acquired the original mine in 1989, and we completed the development of Mine No. 5 in May 2020. The underground operation utilizes continuous mining units employing room-and-pillar mining techniques to produce low-sulfur coal. The preparation plant has throughput capacity of 1,000 tons of raw coal per hour. Coal produced from MC Mining can be shipped via the CSX railroad directly to customers or various transloading facilities on the Ohio River for barge deliveries, or by truck directly to customers or various docks on the Big Sandy River for barge deliveries. MC Mining coal production in 2025 was 0.7 million tons.

Coal Marketing and Sales

We market our coal through established customer relationships and competitive bidding processes, with a significant portion of our volumes sold under long-term coal supply agreements. These contracts provide enhanced predictability of sales volumes and pricing for both us and our customers. While some utility customers have favored shorter-term contracting in recent years, during 2025 approximately 86.5% of our total coal sales were under long-term contracts with committed term expirations ranging from 2026 to 2030. The nomination schedules under these agreements generally provide sufficient visibility for us to balance our contracted commitments with anticipated production levels.

Our long-term contracts vary significantly in structure and terms due to customer-specific requirements and negotiated outcomes. Key provisions may include price adjustment mechanisms tied to market indices or changes in regulatory compliance costs, sourcing and quality specifications, reopener rights, and force majeure terms. Certain agreements allow for volume flexibility within defined ranges. Although price adjustment provisions help mitigate cost variability, they may not fully reflect all changes in our production or operating costs. Failure to reach agreement on a price adjustment or other negotiated terms can lead to early termination of a contract.

Quality assurance remains an integral part of our contracting framework. Most long-term agreements require us to deliver coal within prescribed specifications for heat content, sulfur, ash, moisture, grindability, volatility, and other attributes. Failure to meet these requirements may result in price adjustments, rejection of shipments, or contract termination. Contracted coal may be sourced from specific approved seams or multiple mines, depending on customer requirements and our operational flexibility.

We also participate in international coal markets, primarily through brokered transactions shipping to end-users in Europe, Africa, Asia, North America, and South America. During the year ended December 31, 2025, export tons represented approximately 8.6% of tons sold. For reporting purposes, we attribute export tons to the final destination when known, although title often transfers to brokers before delivery to end-markets.

Reliance on Major Customers

Our customer base includes several large domestic electric utilities. In 2025, we derived more than 10% of our total revenue from each of Louisville Gas and Electric Company and American Electric Power Company Inc. We did not derive 10% or more of our revenues from any other single customer. For more information about these customers, please read “Item 8. Financial Statement and Supplemental Data—Note 20 – Concentration of Credit Risk and Major Customers.”

Coal Competition

We operate in a highly competitive coal market. Our competitiveness is influenced by several factors, including pricing, coal quality, supply reliability, transportation logistics, diversity of supply, and proximity to customers. We are the second largest coal producer in the eastern United States. Our principal competitors include American Consolidated Natural Resources Inc., Core Natural Resources, Inc., Alpha Metallurgical Resources, Inc., Foresight Energy Resources LLC, and Peabody Energy Corporation. We also compete directly with smaller producers in the Illinois Basin and Appalachian regions. In addition, we seek to export a portion of our coal into international coal markets and we compete with companies that produce coal from foreign countries.

Domestic coal pricing is primarily driven by coal consumption patterns of domestic electricity-generating utilities. These patterns depend on overall economic conditions, governmental regulatory developments, weather, and technological developments, as well as competition from alternative generation sources—including natural gas, nuclear energy, and renewables—as well as the relative delivered cost of those fuels compared to coal. Export pricing is influenced by many factors, such as global economic conditions, weather patterns, and global supply and demand, among others.

Coal Transportation

Our coal is transported from our mining complexes to our customers by barge, rail, and truck, reflecting important flexibility advantages in supplying our customers. Depending on the proximity of the customer to the mining complex and the transportation available for delivering coal to that customer, transportation costs can be a substantial part of the total delivered cost of a customer’s coal. Consequently, the availability and cost of transportation constitute important factors in the marketability of coal. We believe our mines are located in favorable geographic locations that minimize transportation costs for our customers, and in many cases, we can accommodate multiple transportation options. Our customers typically negotiate and pay the transportation costs from the mining complex to the destination, which is the standard practice in the industry. Approximately 45.8% of our 2025 sales volume was initially shipped from the mining complexes by barge, 34.8% was shipped from the mining complexes by rail, and 19.4% was shipped from the mining complexes by truck. The rates set by and available capacity of the transportation company serving a particular mine or customer may affect, either adversely or favorably, our marketing efforts concerning coal produced from the relevant mining complex. With respect to our export volumes from the United States to other countries, we generally sell coal to our customers at an export terminal in the United States and we are responsible for the cost of transporting coal to the export terminals. Our export customers generally negotiate and pay for ocean vessel transportation.

Mineral Interest Activities

Our mineral interest activities include both oil & gas and coal mineral interests. Our oil & gas mineral interest business includes all activities related to the oil & gas mineral interests held directly or indirectly by Alliance Minerals and includes Alliance Minerals' equity interest in AllDale III. Our mineral interests are primarily located on private lands in three basins, which are also our areas of focus for future development by operators. These include the Permian (Delaware and Midland), Anadarko (SCOOP/STACK), and Williston (Bakken) Basins. Our developed and undeveloped net acres standardized to a 1/8th royalty equate to approximately 70,000 oil & gas net royalty acres, including approximately 4,000 oil & gas net royalty acres owned through our equity interest in AllDale III.

Our coal mineral interests include substantially all of our coal mineral resources and the majority of our coal mineral reserves which are owned or leased by Alliance Resource Properties and are (a) leased or subleased to our mining complexes or (b) near other internal and external coal mining operations but not yet leased. Our coal mineral interests are located in both the Illinois Basin and the Appalachia Basin.

Oil & Gas Royalties

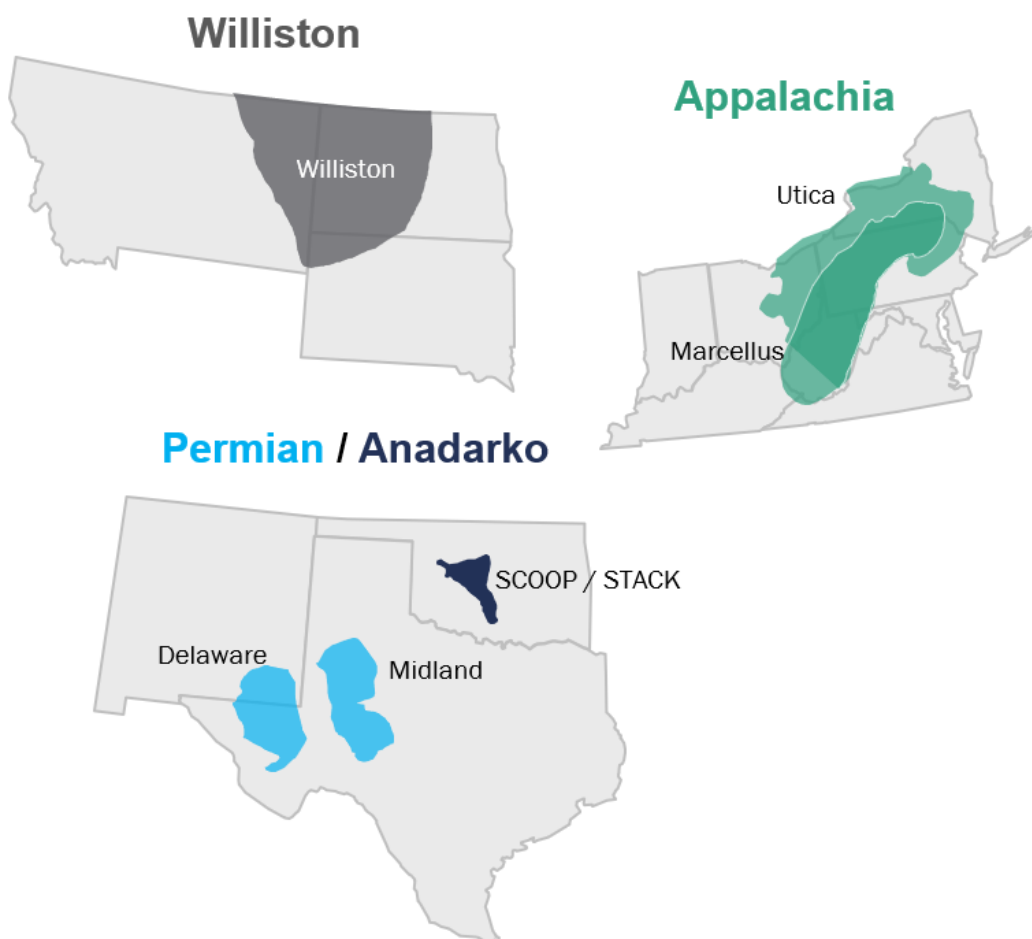
When our oil & gas mineral interests are leased, we typically receive an upfront lease bonus and retain a royalty interest that entitles us to a fixed percentage of production or revenue from the acreage underlying our interests. These royalties are free of operating and capital costs associated with drilling or completing wells and producing oil & gas from those wells. As a result, our exposure is limited to our proportionate share of production and ad valorem taxes. Unlike owners of working interests in oil & gas properties, we are not obligated to fund drilling and completion costs, lease operating expenses, or plugging and abandonment costs associated with oil & gas production.

Leases may be extended beyond the initial term through continuous drilling or production operations, or through extension payments. When production or drilling activity ceases, the lease typically terminates, providing us the opportunity to re-lease the acreage to other operators. This recurring re-lease cycle supports long-term value realization across both developed and undeveloped acreage positions.

The following chart summarizes the production of our oil & gas mineral interests for the years ended December 31, 2025, 2024, and 2023, not including our equity interest in AllDale III:

	Year Ended December 31,		
	2025	2024	2023
Production:			
Oil (MBbls)	1,628	1,501	1,418
Natural gas (MMcf)	6,674	6,304	5,759
Natural gas liquids (MBbls)	908	850	726
BOE (MBbls)	3,648	3,402	3,105

The following map shows the location of our oil & gas mineral interests:



Permian Basin—Delaware and Midland Basins

The Permian Basin ranges from West Texas into southeastern New Mexico and is currently the most active area for horizontal drilling in the United States. The Permian Basin is further subdivided into the Delaware Basin in the west and the Midland Basin in the east. Based on geologic data and the ongoing development by operators, our mineral interests in the Permian Basin contain multiple producing zones of economic horizontal development including but not limited to the Wolfcamp, Spraberry, and Bone Spring formations. Our mineral interest purchases have historically been Permian Basin-weighted in pursuit of the highest risk-adjusted returns. While the Permian Basin remains our primary focus area, we continue to consider acquisitions in other basins which may provide superior risk-adjusted returns.

Anadarko Basin—SCOOP and STACK Plays

The SCOOP play (South Central Oklahoma Oil Province) is located in central Oklahoma in Grady, Garvin, Stephens, and McClain Counties. Based on geologic data and the ongoing development by operators, our mineral interests in the SCOOP play contain multiple producing zones of economic horizontal development including multiple Woodford benches and the Springer Shale. In addition, operators are also currently testing other formations in the area including the Sycamore, Caney, and Osage, which is also referred to as SCORE (Sycamore Caney Osage Resource Expansion). The STACK play (derived from Sooner Trend, Anadarko Basin, Canadian and Kingfisher Counties) is located in central Oklahoma in Kingfisher, Canadian, Caddo, and Blaine Counties. Based on geologic data and the ongoing development by operators, our mineral interests in the STACK play contain multiple producing zones of economic horizontal development including but not limited to the Meramec and Woodford formations.

Williston Basin—Bakken

The Williston Basin stretches from western North Dakota into eastern Montana. Based on geologic data and ongoing development by operators, our mineral interests contain multiple producing zones of economic horizontal development including the Bakken and Three Forks formations.

Other

Our other oil & gas mineral interests are comprised primarily of mineral interests owned in the Appalachia Basin that stretches throughout most of Ohio, West Virginia, and Pennsylvania, and extends into other states. The Appalachia Basin's most active plays in which we have acreage are the Marcellus Shale and Utica plays, which cover most of Pennsylvania, northern West Virginia, and eastern Ohio. In addition to the interests held in the Appalachia Basin, we own a small number of mineral interests in the Tuscaloosa Marine Shale play in Mississippi. AllDale III also owns mineral interests in the Haynesville Shale formation located in northwest Louisiana.

Coal Royalties

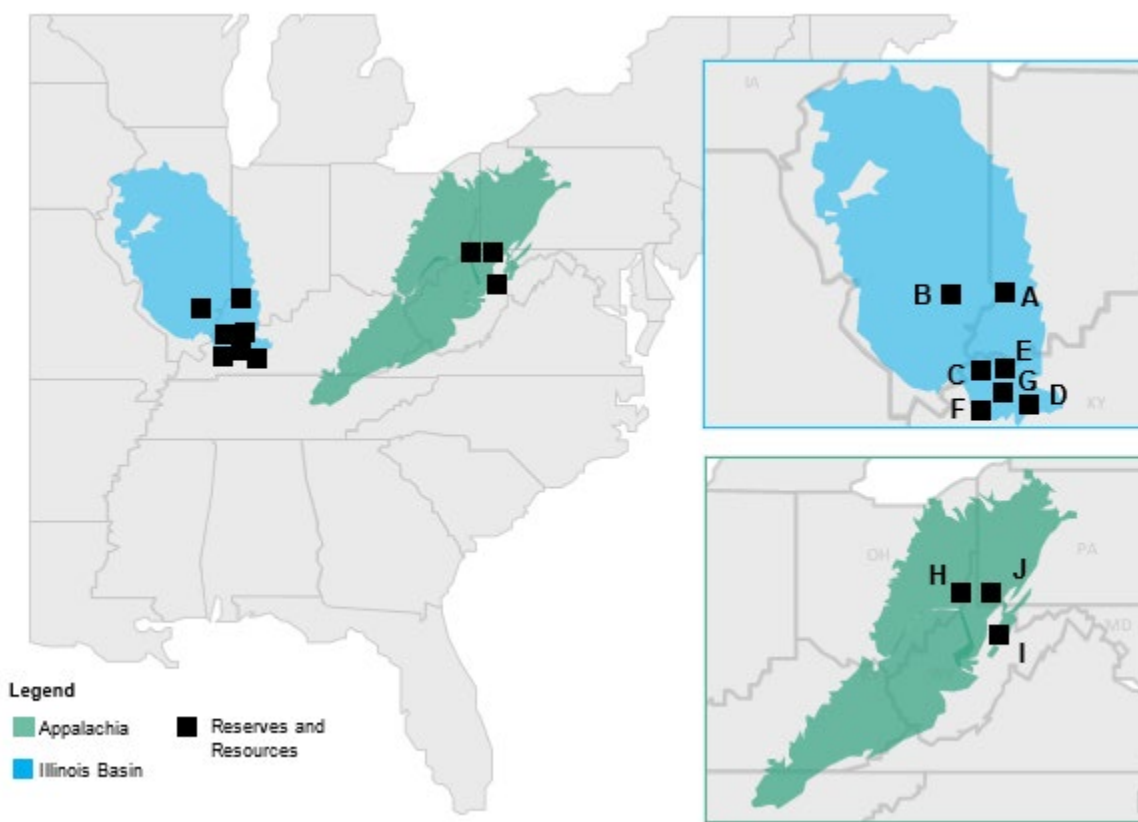
Our Coal Royalties segment includes approximately 509.6 million tons of reserves and substantially all of the 1.07 billion tons of our coal mineral resources. Our coal mineral reserves and resources are located in the Appalachia and Illinois Basins in the United States. These assets support our internal mining operations. We lease our reserves and resources to our mining complexes under long-term leases. Approximately 60% of our royalty-based leases have initial terms of five to 40 years, with substantially all lessees having the option to extend the lease for additional terms.

Under our standard royalty lease, we grant the lessees the right to mine and sell our reserves and resources in exchange for royalty payments based on a percentage of the sale price or a fixed royalty per ton of coal mined and sold. Lessees calculate royalty payments due to us and are required to report tons of coal mined and sold as well as the sales prices of the extracted coal.

The following chart summarizes the coal sales associated with our coal mineral interests for the years ended December 31, 2025, 2024 and 2023.

<u>Coal Regions</u>	Year Ended December 31,		
	<u>2025</u>	<u>2024</u>	<u>2023</u>
	(tons in millions)		
Illinois Basin	20.5	19.8	19.9
Appalachia	3.6	1.3	0.3
Total	<u>24.1</u>	<u>21.1</u>	<u>20.2</u>

The following map shows the location of our coal mineral interests:



Illinois Basin:

A. GIBSON RESERVES AND RESOURCES
B. HAMILTON RESERVES AND RESOURCES
C. RIVER VIEW RESERVES AND RESOURCES
D. WARRIOR RESERVES AND RESOURCES

E. HENDERSON/UNION RESOURCES
F. DOTIKI RESOURCES
G. SEBREE SOUTH RESOURCES

Appalachian Basin:

H. TUNNEL RIDGE RESERVES AND RESOURCES
I. MOUNTAIN VIEW RESERVES AND RESOURCES
J. PENN RIDGE RESOURCES

Illinois Basin

Alliance Resource Properties, either directly or through its subsidiaries, holds coal mineral reserves and resources in the following counties in the Illinois Basin:

- Hopkins County, Kentucky
- Webster County, Kentucky
- Union County, Kentucky
- Henderson County, Kentucky
- Hamilton County, Illinois
- Gibson County, Indiana

Alliance Resource Properties leases some of the reserves and resources in Union and Henderson Counties from WKY CoalPlay or its subsidiaries, which are related parties. For more information about our WKY CoalPlay transactions, please read “Item 8. Financial Statements and Supplementary Data—Note 21 – Related-Party Transactions.”

Approximately 423.5 million tons of proven and probable reserves and 972.5 million tons of measured, indicated and inferred coal mineral resources are controlled by Alliance Resource Properties in the Illinois Basin and are leased/subleased to our mining complexes or held for lease/sublease in the future as follows:

Gibson Reserves and Resources

Approximately 2.4 million tons of the reserves and resources are currently leased/subleased or held for lease/sublease to Gibson.

Hamilton Reserves and Resources

Approximately 534.4 million tons of the reserves and resources are currently leased/subleased or held for lease/sublease to Hamilton.

River View Reserves and Resources

Approximately 280.3 million tons of the reserves and resources are currently leased/subleased or held for lease/sublease to River View.

Warrior Reserves and Resources

Approximately 44.6 million tons of the reserves and resources are currently leased/subleased or held for lease/sublease to Warrior.

Henderson/Union Resources

Approximately 415.2 million tons of the resources are not under lease or currently anticipated to be leased by our operating companies. Leasing of these properties is dependent upon further development by our operating subsidiaries or third-party mining complexes, which is regulatory and market dependent.

Dotiki Resources

Approximately 76.0 million tons of the resources are currently leased/subleased or held for lease/sublease to Webster.

Sebree South Resources

Approximately 43.0 million tons of the resources are currently leased/subleased to Sebree.

Appalachia Basin

Alliance Resource Properties, either directly or through its subsidiaries, holds coal mineral reserves and resources in the following counties in the Appalachian Basin:

- Brooke County, West Virginia
- Grant County, West Virginia
- Ohio County, West Virginia
- Tucker County, West Virginia
- Washington County, Pennsylvania

Approximately 86.1 million tons of reserves and 85.6 million tons of coal mineral resources are controlled by Alliance Resource Properties in the Appalachian Basin and are leased/subleased to our mining complexes or held for lease/sublease in the future as follows:

Tunnel Ridge Reserves and Resources

Approximately 82.5 million tons of the reserves and resources are currently leased/subleased or held for lease/sublease to Tunnel Ridge.

Mountain View Reserves and Resources

Approximately 11.2 million tons of the reserves and resources are currently leased/subleased or held for lease/sublease to Mettiki (WV).

Penn Ridge Resources

Approximately 78.0 million tons of the resources are not under a lease. The resources are near our Tunnel Ridge mining complex and leasing of these resources is dependent upon further development by Tunnel Ridge or third-party mining complexes, which is regulatory and market dependent.

Minerals Interests Competition

Competition for mineral interests—both coal and oil & gas interests—remains significant, driven by a limited supply of high-quality resource acreage and increasing interest from mineral aggregators, operators, private equity sponsors, and land companies. Our ability to expand our mineral interests portfolio depends on our continued success in identifying attractive opportunities, evaluating potential returns, and executing transactions in a competitive acquisition environment that often involve auction processes.

In the oil & gas sector, we compete not only with companies that acquire mineral interests, but also with integrated enterprises that explore for and produce hydrocarbons and, in some cases, operate midstream, refining, or marketing businesses. These competitors may have access to technical data, development insights, and operational information that exceed what is available to us as a mineral owner, providing them with advantages in underwriting or valuing mineral opportunities. In addition, many competitors possess greater financial and human resources than us, which may better position them to compete for larger or premium-priced assets. Demand for oil & gas itself remains sensitive to relative fuel economics, regulatory developments, conservation trends, and the availability of alternative energy sources.

We also face competition in the acquisition of coal mineral reserves and resources. Competitors include land companies, domestic coal producers, and international steel producers seeking to secure long-term supply. For the reserves we lease to our mining complexes, competitive pressures mirror those affecting the coal industry more broadly—primarily the coal price at the mine, coal quality, transportation cost from the mine to the customer, development costs, and the reliability of supply. Demand for our coal and the prices that our lessees obtain are further influenced by the demand for electricity and steel, as well as government regulations, technological developments, and the relative cost and availability of alternative generation sources, including nuclear, natural gas, wind, solar, and hydroelectric power. All of these factors may impact the royalties attributable to the production of our reserves.

Oil & Gas Minerals Interests - Seasonal Nature of Business

Generally, demand for oil increases during the summer months and decreases during the winter months while demand for natural gas increases during the winter and summer months and decreases during the spring and fall months. Certain buyers of natural gas use natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations. Seasonal weather conditions and lease stipulations can limit drilling and producing activities and other oil & gas operations in a portion of our leasing areas. These seasonal anomalies can pose challenges for the operators in meeting well-drilling objectives and can increase competition for equipment, supplies, and personnel during the spring and summer months, which could lead to shortages and increase costs or delay operations.

Other Growth Investments

AROP II's strategy is to make strategic investments in what we believe to be attractive opportunities that support the growth and development of technology and energy and related infrastructure. We intend to pursue opportunities that leverage our core competencies and relationships with electric utilities, industrial customers, and federal and state governments. Our strategy is to continue to identify and make strategic investments in the growth and development of technology, energy and related infrastructure and other opportunities that may create new platforms for future lines of business, which, if successful, could lead to long-term growth and cash flow generation.

Matrix Group

Matrix Group provides a variety of technology products and services for our mining operations and certain industrial and mining technology products and services to third parties around the world. Matrix Group's products and services include data network, communication and tracking systems, mining proximity detection systems, industrial collision avoidance systems, and data and analytics software. In addition, Matrix Design has entered into an agreement with Infinitem to jointly develop and distribute high-efficiency motors and advanced motor controllers designed specifically for the mining industry. Under the agreement, Matrix Design will integrate Infinitem's motor technology into mining equipment of our operating subsidiaries to provide performance validation in production environments for jointly developed products and to improve our operational efficiency. Matrix Design will also work with Infinitem to market the jointly developed technology products to third parties worldwide. We acquired Matrix Design in September 2006. Matrix Group has become a leader in collision avoidance and proximity detection technologies, providing safety and productivity solutions for mining companies worldwide, while extending its reach into other industrial applications.

Bitiki

Bitiki began crypto-mining activities during the second half of 2020. Bitiki also hosts third-party crypto-miners for a fee. As of December 31, 2025, we had 3,702 active miners and 1,056 hosted machines. We hold 592.01 bitcoin valued at \$51.8 million as of December 31, 2025.

Other Growth Investments

As of December 31, 2025, we have investments in Infinitem, NGP ET IV, and Gavin Generation. Please read "Item 8. Financial Statements and Supplementary Data—Note 3 – Variable Interest Entities" and "—Note 10 – Investments" for more information on our growth investments.

- Infinitem is a Texas-based developer and manufacturer of electric motors featuring printed circuit board stators that have the potential to result in motors that are smaller, lighter, quieter, more efficient and capable of operating at a fraction of the carbon footprint of conventional electric motors.
- NGP ET IV focuses on investments that are part of the energy transition by partnering with top-tier management teams and investing growth equity in companies that drive or enable the growth of renewable energy, the electrification of our economy, or the efficient use of energy.
- Gavin Generation is a limited partnership that owns, indirectly, an interest in a joint venture holding company formed with a third party that indirectly owns and operates a coal-fired power plant.

Environmental, Health, and Safety Regulations

Our coal operations, and those of the operators on the properties in which we hold oil & gas mineral interests, are subject to extensive regulation by federal, state, and local authorities on matters such as:

- employee health and safety;
- permits and other licensing requirements for mining or exploration and production activities;
- air quality standards;
- water quality standards;
- storage of petroleum products and substances that are regarded as hazardous under applicable laws or that, if spilled, could reach waterways or wetlands;
- plant and wildlife protection that could limit or prohibit mining or exploration and production activities;
- restriction of the types, quantities, and concentration of materials that can be released into the environment in the performance of mining or exploration and production activities;
- initiation of investigatory and remedial measures to mitigate pollution from former or current operations, such as restoration of waste ponds, mining areas, drilling pits, and plugging of abandoned wells;
- storage and handling of explosives;
- wetlands protection;
- surface subsidence from underground mining; and

- the effects, if any, that mining has on groundwater quality and availability.

Failure to comply with environmental laws and regulations may result in the assessment of administrative, civil, and criminal sanctions, including monetary penalties, the imposition of strict, joint and several liability, investigatory and remedial obligations, and the issuance of injunctions limiting or prohibiting some or all of the operations on our properties. The regulatory burden on fossil-fuel industries increases the cost of doing business and consequently affects profitability. The trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations or reinterpretation of enforcement policies that result in more stringent and costly obligations could increase our or our mineral interest operators' costs and adversely affect our performance.

In addition, the utility industry is subject to extensive regulation regarding the environmental impact of its power generation activities, which has adversely affected the demand for coal. It is possible that new legislation or regulations may be adopted, or that existing laws or regulations may be differently interpreted or more stringently enforced, any of which could have a significant impact on our mining operations, our customers' ability to use coal, or the value of or amount of royalties received from our mineral interests. For more information, please see the risk factors described in "Item 1A. Risk Factors" below.

We are committed to conducting mining operations in compliance with applicable federal, state, and local laws and regulations. However, because of the extensive and detailed nature of these regulatory requirements, particularly the regulatory system of MSHA where citations can be issued without regard to fault and many of the standards include subjective elements, it is not reasonable to expect any coal mining company to be free of citations. When we receive a citation, we attempt to remediate any identified condition as soon as practicable. While we have not quantified all of the costs of compliance with applicable federal and state laws and associated regulations, those costs have been and are expected to continue to be significant. Compliance with these laws and regulations has substantially increased the cost of coal mining for domestic coal producers.

Expenditures for environmental matters have not been material in recent years. We have accrued for the present value of the estimated cost of asset retirement obligations and mine closings, including the cost of treating mine water discharge, when necessary. The accruals for asset retirement obligations and mine closing costs are based on permit requirements and the estimated costs and timing assumptions of asset retirement obligations and mine closing procedures. Although management believes it has made adequate provisions for all expected reclamation and other costs associated with mine closures, future operating results would be adversely affected if these accruals were insufficient.

Mining Permits and Approvals

Numerous governmental permits or approvals are required for mining operations. Applications for permits require extensive engineering and data analysis and presentation and must address a variety of environmental, health, and safety matters associated with a proposed mining operation. These matters include the manner and sequencing of coal extraction, the storage, use, and disposal of waste and other substances and impacts on the environment, the construction of water containment areas, and reclamation of the area after coal extraction. Meeting all requirements imposed by any of these authorities may be costly and time-consuming and may delay or prevent the commencement or continuation of mining operations.

The permitting process for certain mining operations can extend over several years and can be subject to administrative and judicial challenges, including by the public. Some required mining permits are becoming increasingly difficult to obtain in a timely manner, or at all. We cannot assure you that we will not experience difficulty or delays in obtaining mining permits in the future or that a current permit will not be revoked.

We are required to post bonds to secure performance under our permits. Under some circumstances, substantial fines, and penalties, including revocation of mining permits, may be imposed under the laws and regulations described above. Monetary sanctions and, in severe circumstances, criminal sanctions may be imposed for failure to comply with these laws and regulations. Regulations also provide that a mining permit can be refused or revoked if the permit applicant or permittee owns or controls, directly or indirectly through other entities, mining operations that have outstanding environmental violations. Although, like other coal companies, we have been cited for violations in the ordinary course of our business, we have never had a permit suspended or revoked because of any violation, and the penalties assessed for these violations have not been material.

Mine Health and Safety Laws

The operation of our mines is subject to FMSHA and regulations adopted pursuant thereto. FMSHA imposes extensive and detailed safety and health standards on numerous aspects of mining operations, including training of mine personnel, mining procedures, blasting, the equipment used in mining operations, and numerous other matters. MSHA monitors and rigorously enforces compliance with these federal laws and regulations. In addition, the states where we operate have individual state programs for mine safety and health regulation and enforcement. Federal and state safety and health regulations affecting the coal mining industry are perhaps the most comprehensive and rigorous system in the United States for the protection of employee safety and have a significant effect on our operating costs. Although many of the requirements primarily impact underground mining, our competitors in the areas in which we operate are subject to the same laws and regulations.

FMSHA has been construed as authorizing MSHA to issue citations and orders pursuant to the legal doctrine of strict liability, or liability without fault, and FMSHA requires the imposition of a civil penalty for each cited violation. Negligence and gravity assessments, along with other factors, can result in the issuance of various types of orders, including orders requiring withdrawal from the mine or the affected area, and some orders can also result in the imposition of civil penalties. FMSHA also contains criminal liability provisions. For example, criminal liability may be imposed upon corporate operators who knowingly and willfully authorize, order, or carry out violations of the FMSHA, or its mandatory health and safety standards. Effective January 15, 2025, MSHA amended 30 CFR Part 100 regarding criteria and procedures for proposed assessment of civil penalties for violations. As provided by the Inflation Adjustment Act, the increased penalty levels apply to any penalties assessed after January 15, 2025.

The MINER Act significantly amended the FMSHA, imposing more extensive and stringent compliance standards, increasing criminal penalties, establishing a maximum civil penalty for non-compliance, and expanding the scope of federal oversight, inspection, and enforcement activities. Following the passage of the MINER Act, MSHA has issued new or more stringent rules and policies on a variety of topics, including:

- sealing off abandoned areas of underground coal mines;
- mine safety equipment, training, and emergency reporting requirements;
- substantially increased civil penalties for regulatory violations;
- training and availability of mine rescue teams;
- underground “refuge alternatives” capable of sustaining trapped miners in the event of an emergency;
- flame-resistant conveyor belts, fire prevention and detection, and use of air from the belt entry; and
- post-accident two-way communications and electronic tracking systems.

MSHA continues to interpret and implement various provisions of the MINER Act, along with introducing new proposed regulations and standards contained in the 30 Code of Federal Regulations (30 CFR).

MSHA has finalized a number of rules related to controlling exposure to respirable dusts within the mining environment, including coal mine dust and silica, which has resulted in progressively stricter exposure limits imposed by MSHA regulations. These requirements impose a number of dust monitoring obligations and mine ventilation requirements on our operations. Compliance with these rules can result, and has resulted, in increased costs on our operations, including, but not limited to, the purchasing of new equipment and the hiring of additional personnel to assist with monitoring, reporting, and recordkeeping obligations and additional medical evaluations.

MSHA has also published, and may continue to publish, requests for information on various mining topics that may result in additional rules applicable to our operations. Recent requests include topics such as engineering controls and exposure of underground miners to diesel exhaust. Recent MSHA rulemaking actions include, for example:

- In July 2025, MSHA published eighteen notices of proposed rulemaking aimed at streamlining mine operations. A central theme of these proposals is the limitation of district manager authority. Other proposals focus on loosening existing requirements, such as revising standards for flame safety lamps and blacksmith shops, and updating diesel particulate matter provisions to reflect current enforcement practices while maintaining existing exposure limits.
- In April 2024, MSHA adopted a rule on respirable crystalline silica, most commonly found in the mining environment through quartz. The rule, *Lowering Miners’ Exposure to Respirable Crystalline Silica & Improving Respiratory Protection*, became final on June 17, 2024. The final rule added additional requirements to the

existing MSHA respirable coal dust standards, as well as set forth new or revised silica standards for exposure sampling, corrective actions, medical surveillance for metal and non-metal miners, medical evaluations conducted by a physician or other licensed health care professional for miners required to wear a respirator, and respiratory protection programs for all mines. Compliance for metal and nonmetal mines goes into effect in April 2026. Compliance for coal mine operators was set to go into effect on April 14, 2025, but a U.S. Circuit Court of Appeals issued a temporary stay on April 4, 2025. As a result, enforcement remains uncertain, subject to this ongoing litigation. In addition, on November 26, 2025, MSHA indicated that the agency would reconsider portions of the rule, which could affect future requirements and associated compliance costs.

- In December 2024, MSHA adopted a rule to revise Testing, Evaluation, and Approval of Electric Motor-Driven Mine Equipment and Accessories within underground mining environments, adopting various voluntary consensus standards to promote innovation in mine safety and health technologies. The rule became final on December 10, 2024, with an effective date of January 9, 2025. Compliance with the revised standards may require us to upgrade, retrofit, or replace certain equipment at our facilities to meet the newly adopted consensus standards.

It is uncertain whether any of the above or various other proposed rules or requests for information would have material impacts on our operations or our costs of operation.

Subsequent to the passage of the MINER Act, several states have enacted legislation addressing issues such as mine safety and accident reporting, increased civil and criminal penalties, and increased inspections and oversight. Additionally, state administrative agencies can promulgate administrative rules and regulations affecting our operations. Other states may pass similar legislation or administrative regulations in the future.

Some of the costs of complying with existing regulations and implementing new safety and health regulations may be passed on to our customers. Although we have not quantified the full impact, implementing and complying with these new federal and state safety laws and regulations has had, and are expected to continue to have, an adverse impact on our results of operations and financial position.

Black Lung Benefits Act

The BLBA requires businesses that conduct current mining operations to make payments of black lung benefits to current and former coal miners with black lung disease, to some survivors of a miner who dies from this disease, and to a trust fund for the payment of benefits and medical expenses under circumstances including where no responsible coal mine operator has been identified for claims. In addition, the BLBA provides that some claims for which coal operators not affiliated with us had previously been responsible are or will become obligations of the government trust funded by the excise tax referenced in this paragraph. The Federal government established such a trust fund that is funded by an excise tax on industry-wide production of up to \$1.10 per ton of coal from underground mines and up to \$0.55 per ton of coal from surface mines, neither amount to exceed 4.4% of the gross sales price. The coal we sell into international markets is generally not subject to the excise tax referenced in this paragraph. The Partnership recognized expenses related to the BLBA excise tax of \$31.7 million for the year ended December 31, 2025. Please read “Item 8. Financial Statements and Supplementary Data—Note 13 – Accrued Workers’ Compensation and Pneumoconiosis Benefits.”

Workers’ Compensation and Black Lung

We provide income replacement and medical treatment for work-related traumatic injury claims as required by applicable state laws. Workers’ compensation laws also provide for the potential compensation of survivors of workers who suffer employment-related deaths. We generally self-insure this potential expense using our actuary estimates of the cost of present and future claims. In addition, coal mining companies are subject to federal legislation and various state statutes for the payment of medical and disability benefits to eligible recipients related to coal worker’s pneumoconiosis, or black lung. We also provide for these claims through self-insurance programs. The DOL’s OWCP is responsible for authorizing coal mine operators to self-insure for federal black lung and for setting applicable security amounts. In December 2024, the OWCP issued a final rule revising its regulations authorizing coal producers to self-insure and for determining appropriate security amounts. This change in requirements for security posted to self-insure black lung liabilities could result in the Partnership being required to post additional security for its obligations, which could reduce the amount of our borrowing capacity under our available financing arrangements by the amount of such additional security. Traditionally, our pneumoconiosis benefits liability has been calculated using the service cost method based on the actuarial present value of the estimated pneumoconiosis benefits obligation. Our actuarial calculations have been based

on numerous assumptions including disability incidence, medical costs, mortality, death benefits, dependents, and discount rates. The impact of OWCP's new actuarial assumptions is presently under review but can result in the Partnership's estimated pneumoconiosis benefits obligations increasing significantly. For more information concerning our requirement to maintain bonds to secure our workers' compensation obligations, see the discussion of surety bonds below under "—Bonding Requirements."

The Patient Protection and Affordable Care Act, enacted in 2010, included significant changes to the federal black lung program retroactive to 2005, including an automatic survivor benefit paid upon the death of a miner with an awarded black lung claim and establishes a rebuttable presumption with regard to pneumoconiosis among miners with 15 or more years of coal mine employment that are totally disabled by a respiratory condition. These changes have increased, and may continue to increase, our costs. We may also be liable under various state statutes with respect to black lung claims.

Surface Mining Control and Reclamation Act

The SMCRA and similar state statutes establish operational, reclamation, and closure standards for all aspects of surface mining as well as many aspects of deep mining. Although we have never had mountaintop removal mining activity and we currently have no surface mining activity, SMCRA nevertheless requires that comprehensive environmental protection and reclamation standards be met during the course of and upon completion of our mining activities.

SMCRA and similar state statutes require, among other things, that mined property be restored in accordance with specified standards and approved reclamation plans. SMCRA requires us to restore the surface to approximate the original contours as contemporaneously as practicable with the completion of surface mining operations. Federal law and some states require mine operators to replace water supplies and repair or compensate for surface structure damage caused by mining operations, including longwall mining and other mining methods. We have accrued \$157.6 million for the estimated costs of reclamation and mine closing, including the cost of treating mine water discharge when necessary. Please read "Item 8. Financial Statements and Supplementary Data—Note 15 – Asset Retirement Obligations."

In addition, the Abandoned Mine Lands Program, which is part of SMCRA and relates to industry-wide operations, imposes a reclamation fee on all current mining operations, the proceeds of which are used to restore mines closed before 1977. The fee expired on September 30, 2021, and was reauthorized through September 30, 2034, under the Infrastructure Investment and Jobs Act which was signed on November 15, 2021. The fee, as reauthorized, for surface-mined and underground-mined coal is \$0.224 per ton and \$0.096 per ton, respectively, through September 30, 2034. In addition, states from time to time have increased and may continue to increase their fees and taxes to fund reclamation or orphaned mine sites and acid mine drainage control on a statewide basis.

Under SMCRA, responsibility for unabated violations, unpaid civil penalties, and unpaid reclamation fees of independent contract mine operators and other third parties can be imputed to other companies that are deemed, according to the regulations, to have "owned" or "controlled" the third-party violator. Sanctions against the "owner" or "controller" are quite severe and can include being blocked from receiving new permits and having any permits revoked that were issued after the time of the violations or after the time civil penalties or reclamation fees became due. We are not aware of any currently pending or asserted claims against us relating to the "ownership" or "control" theories discussed above. However, we cannot assure you that such claims will not be asserted in the future.

Bonding Requirements

Federal and state laws require bonds to secure our obligations to reclaim lands used for mining, to pay federal and state workers' compensation, to pay certain black lung claims or estimated black lung claims, and to satisfy other miscellaneous obligations. These bonds are typically renewable on a yearly basis. It has become increasingly difficult for us and for our competitors to secure new surety bonds without posting collateral and, in some cases, it is unclear what level of collateral will be required. In addition, surety bond costs have increased while the market terms of surety bonds have generally become less favorable to us. It is possible that surety bond issuers may refuse to renew bonds or may demand additional collateral upon those renewals. Our failure to maintain or inability to acquire surety bonds that are required by federal and state laws would have a material adverse effect on our ability to produce coal, which could affect our profitability and cash flow. For additional information, please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—*Cash Requirements*."

Air Emissions

The CAA and similar state and local laws and regulations regulate emissions into the air and affect coal mining, as well as oil & gas, operations. The CAA imposes permitting requirements and, in some cases, requirements to install certain emissions control equipment, achieve certain emissions standards, or implement certain work practices on sources that emit various air pollutants. The CAA also indirectly affects coal mining operations by extensively regulating the air emissions of coal-fired electric power generating plants and other coal-burning facilities. There has been a series of federal rulemakings focused on emissions from coal-fired electric generating facilities. Installation of additional emissions control technology and any additional measures required under applicable federal and state laws and regulations related to air emissions will make it more costly to operate coal-fired power plants and possibly other facilities that consume coal and, depending on the requirements of SIPs, could make fossil fuels a less attractive fuel alternative in the planning and building of power plants in the future. A significant reduction in fossil fuels' share of power generating capacity could have a material adverse effect on our business, financial condition, and results of operations.

In addition to the GHG issues discussed below, the air emissions programs that may affect our operations or the operations of those on the properties in which we hold mineral interests, directly or indirectly, include but are not limited to the following:

- The EPA periodically reviews and may revise the NAAQS, which can require additional SIP obligations and emissions controls. In addition, the EPA's regional haze program requires SIPs intended to protect visibility in certain protected areas, and the EPA may disapprove SIPs and impose a FIP requiring additional controls. These air quality programs, and related rulemaking and litigation, may increase our customers' operating and capital costs and may contribute to reduced utilization or retirements of coal-fired generating units, which could adversely affect demand and prices for our coal and adversely affect our business and results of operations.
- A range of federal and state air emissions programs under the CAA regulate sulfur dioxide, nitrogen oxides, particulate matter, and other pollutants from coal-fired electric generating units and other industrial sources. These programs include the EPA's Title IV Acid Rain Program and interstate transport requirements implemented through SIPs and federal rules addressing the interstate movement of ozone and particulate-forming emissions. Compliance with these requirements may be achieved through a combination of emissions allowances and/or emissions budgets, installation or operation of pollution control technologies, fuel switching, and/or reduced utilization. In 2025, we sold 89.2% of our total tons to electric utilities in the United States, substantially all of which was sold to utility plants with installed pollution control devices.
- In May 2020, the EPA issued a final rule that reversed the Agency's prior determination from 2000 to 2016 that it was "appropriate and necessary" to regulate hazardous air pollutants from coal-fueled EGUs under the MATS rule, which regulates the emission of mercury and other metals, fine particulates, and acid gases such as hydrogen chloride from coal and oil-fired power plants. However, in February 2023, the EPA published a final revocation of the May 2020 finding. Then, in May 2024, the EPA published a final rule to amend the MATS rule, which further limits the emission of non-mercury hazardous air pollutant metals from existing coal-fired power plants, tightens the emission standard for mercury for existing lignite-fired power plants, and strengthens emissions monitoring and compliance requirements. However, in February 2026, the EPA issued a final rule repealing the amendments finalized in 2024, reverting to the initial emission standards and compliance options established in 2012. Broadly, the MATS program has required many electric power generators to make capital investments to retrofit power plants and may contribute to retirements of older coal-fired generating units. Such retirements could reduce demand for coal. Apart from MATS, several states have enacted or proposed regulations requiring reductions in mercury emissions from coal-fired power plants, and federal legislation to reduce mercury emissions from power plants has been proposed. Regulation of mercury emissions by the EPA, states, or Congress may decrease the future demand for coal.
- The EPA's regional haze program is designed to protect and improve visibility at and around national parks, national wilderness areas, and international parks. Under the program, states are required to develop SIPs to improve visibility. Typically, these plans call for reductions in sulfur dioxide and nitrogen oxide emissions from coal-fueled electric plants. In prior cases, the EPA has decided to negate the SIPs and impose stringent requirements through FIPs. The regional haze program, including particularly the EPA's FIPs, and any future regulations may restrict the construction of new coal-fired power plants whose operation may impair

visibility at and around federally protected areas and may require some existing coal-fired power plants to install additional control measures designed to limit haze-causing emissions. These requirements could limit the demand for coal in some locations. On January 6, 2026, the EPA finalized a significant revision to the Regional Haze Rule, extending the deadline for the next round of periodic SIP revisions from July 31, 2028, to July 31, 2031. On January 9, 2026, the agency fully disapproved Colorado's regional haze SIP. In February 2026, the EPA issued updated, non-binding guidance for regional haze SIPs for the second implementation period addressing how states should evaluate "energy and non-air quality environmental impacts" in reasonable progress determinations. The guidance encourages states to consider potential impacts on electrical grid reliability, including impacts of any electric generating unit closure that would become federally enforceable if approved into a SIP, and advises that the EPA does not support states encouraging or forcing an electric generating facility to close in order to comply with regional haze requirements.

- The EPA's NSR program under the CAA in certain circumstances requires existing coal-fired power plants, when modifications to those plants significantly increase emissions, to install more stringent air emissions control equipment. The Department of Justice, on behalf of the EPA, has filed lawsuits against a number of coal-fired electric generating facilities alleging violations of the NSR program. The EPA has alleged that certain modifications have been made to these facilities without first obtaining certain permits issued under the program. Several of these lawsuits have been settled, but others remain pending. In October 2020, the EPA finalized a rule to clarify the process for evaluating whether the NSR permitting program would apply to a proposed modification of a source of air emissions. The EPA proposed revisions in February 2024 to its NSR preconstruction permitting regulations to address concerns raised in petition for reconsideration litigation. Depending on the ultimate resolution of the EPA's litigation and any potential final rule, demand for coal could be affected.
- The EPA's NSPS under the CAA require the reduction of certain pollutants and methane emissions from certain stimulated oil & gas wells for which well completion operations are conducted, require that most wells use reduced emission completions, also known as "green completions," and establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, and pneumatic controllers and storage vessels. In December 2023, the EPA issued its final methane rules, known as OOOOb and OOOOc, that establish new source and first-time existing source standards of performance for GHG and VOC emissions for crude oil and natural gas well sites, natural gas gathering and boosting compressor stations, natural gas processing plants, and transmission and storage facilities. However, in March 2025, the EPA announced plans to reconsider OOOOb and OOOOc. Additionally, in November 2025, the EPA finalized an interim rule extending the compliance deadlines for certain provisions provided in OOOOb and OOOOc. Litigation challenging the EPA's final interim rule extending such compliance deadlines for new and existing oil and gas sources remains pending. To the extent that these rules are implemented as originally promulgated, oil & gas production on the properties in which we hold mineral interests could be adversely affected to the extent the rules and any of their requirements impose increased operating costs on the oil & gas industry.

GHG Emissions

Combustion of fossil fuels, such as the coal we produce and the oil & gas produced from our mineral interests, results in the emission of GHGs, such as carbon dioxide and methane. Combustion of fuel for mining equipment used in coal production also emits GHGs. Future regulation of GHG emissions in the United States could occur pursuant to new or existing domestic legislation, or regulation by the EPA; however, in February 2026, the Trump administration finalized a rule repealing the "Endangerment Finding." This served as the basis for the majority of EPA's GHG related regulations. It is uncertain what impact the repeal of the Endangerment Finding will have on such regulations, and at least one lawsuit has been filed in federal court challenging the EPA's rule revoking its Endangerment Finding.

At this time, no comprehensive climate change regulation has been adopted at the federal level in the United States. However, many states, regions, and governmental bodies have adopted GHG initiatives and have or are considering the imposition of fees or taxes based on the emission of GHGs by certain facilities, including coal-fired electric generating facilities, either as part of cap and trade, carbon tax, or climate "superfund" laws. For example, in December 2024, New York adopted a law requiring companies that emitted over 1 billion tons of GHG emissions into the atmosphere between 2000 and 2018, with sufficient connections to the state of New York, to pay into a "climate superfund" to support climate-related adaptation and mitigation projects. We have been identified by New York as a potentially responsible party under

the law, which is being challenged in court; but, to date, we have not received any cost recovery demands. Vermont has passed its own climate “superfund” law, other states, such as Illinois, are attempting to pass their own climate “superfund” laws, and many others have announced their intent to increase the use of renewable energy sources, displacing coal, and other fossil fuels. Depending on the particular regulatory program that may be enacted, at either the federal or state level, and the outcome of any legal challenges, the demand for coal and oil & gas could be negatively impacted, which would have an adverse effect on our operations.

The EPA has sought to regulate GHG emissions from stationary sources, such as coal-fueled power plants, based on its authority under the CAA. In August 2015, the EPA issued its final CPP Rule, which established carbon pollution standards for power plants. Following legal challenges, the EPA repealed the CPP and finalized the ACE rule, which was also subject to legal challenge. In June 2022, the U.S. Supreme Court in *West Virginia v. EPA* found that the EPA had acted outside the bounds of the agency’s authority in promulgating of the CPP. In May 2024, the EPA finalized a rule that repealed the ACE rule and established GHG standards and guidelines that require coal fired power plants to (1) convert to natural gas co-firing by January 1, 2030 and then retire by 2039, (2) install by 2032 carbon capture and sequestration technology capable of capturing 90% of all CO₂ emissions, or (3) cease operations by 2032. The May 2024 rule was challenged in the D.C. Circuit Court, but the U.S. Supreme Court denied the challengers’ request to stay implementation of the rule pending the outcome of the litigation. On June 17, 2025, the EPA issued a proposed rule that would repeal all GHG emissions standards for fossil fuel-fired power plants, including the May 2024 rule.

Several rulemakings have been issued under the NSPS that constrain the GHG emissions of fossil-fuel-fired power plants. In October 2015, EPA published its final rule on performance standards for GHG emissions from new, modified, and reconstructed EGUs, which required use of efficient supercritical pulverized coal boilers that use partial post-combustion carbon capture and storage technology and imposed a new emission standard. Following legal challenge, the EPA undertook a review of the October 2015 rule and in December 2018, the EPA issued a proposed rule to replace the October 2015 rule, including revising the BSER for newly constructed coal-fired EGUs. In May 2024, however, the EPA issued a final NSPS rule for GHG emissions from new and reconstructed fossil fuel-fired combustion turbines, which notably, formally withdrew the December 2018 proposed amendments to the NSPS for GHG emissions from coal-fired EGUs. On June 17, 2025, the EPA issued a proposed rule that would repeal all GHG emissions standards for fossil fuel-fired power plants, including the May 2024 final NSPS rule.

There are further uncertainties surrounding the potential impacts and costs associated with the reduction of GHG emissions, such as: protests and challenges to the permitting of new fossil-fuel infrastructure by environmental organizations and state regulators; state tort liability or regulatory penalties or fines; and state adoption of “renewable energy standards” or “renewable portfolio standards,” which encourage or require electric utilities to obtain a certain percentage of their electric generation portfolio from renewable resources by a certain date. For example, several states have announced their intent to have renewable energy comprise 100% of their electric generation portfolio. To the extent these requirements or similar requirements that may be enacted or adopted in the future affect our current and prospective customers or those of our mineral interest producers, they may reduce the demand for our coal and the oil & gas produced from the properties in which we hold mineral interests. For more information, see our risk factor titled “We, our customers, or the operators of our oil & gas mineral interests could be subject to litigation related to climate change.”

In addition, environmental advocacy groups have filed a variety of judicial challenges claiming that the environmental analyses conducted by federal agencies before granting permits and other approvals necessary for certain coal activities do not satisfy the requirements of the NEPA. These groups assert that the environmental analyses in question do not adequately consider the climate change impacts of these particular projects. However, as a result of recent court rulings and the change in presidential administrations, there is significant uncertainty with respect to current and future NEPA regulations. For example, in April 2025, the U.S. Department of Interior issued a new “alternative arrangements” policy for NEPA reviews of proposed fossil fuel projects, providing for shorter environmental review. Also in May 2025, the U.S. Supreme Court held in *Seven County Infrastructure Coalition v. Eagle County, Colorado* that courts must grant agencies “substantial judicial deference” with respect to the scope and content of their NEPA reviews when considering NEPA challenges, and that an agency may decline to evaluate environmental effects from separate projects upstream or downstream from the project at issue. Further, in September 2025, the White House Council on Environmental Quality issued new guidance to federal agencies implementing NEPA, encouraging agencies to limit their NEPA reviews, rely more heavily on sponsor-prepared documents, and streamline the NEPA process. While the impact of these developments is unclear at this time, any disruption in our ability to obtain permits could result in costs that could have a material adverse effect on our business, financial condition and results of operations.

Many states and regions have adopted GHG initiatives and certain governmental bodies have or are considering the imposition of fees or taxes based on the emission of GHG by certain facilities, including coal-fired electric generating facilities. For example, the RGGI calls for the implementation of a cap-and-trade program aimed at reducing carbon dioxide emissions from power plants in participating states. The members of RGGI have established in statutes and/or regulations a carbon dioxide trading program. However, in November 2025, Pennsylvania officially withdrew from RGGI. Similar to RGGI, five western states launched the Western Climate Initiative. We cannot predict what other regional GHG reduction initiatives may arise in the future.

It is possible that future international, federal, and state initiatives to control GHG emissions could result in increased costs associated with fossil-fuel production and consumption, such as costs to install additional controls to reduce carbon dioxide emissions or costs to purchase emissions reduction credits to comply with future emissions trading programs. Such increased costs for fossil-fuel consumption could result in some customers switching to alternative sources of fuel, or otherwise adversely affect our operations and demand for our products, or those of the operators of our mineral interests, which could have a material adverse effect on our business, financial condition, and results of operations. Finally, activists may try to hamper fossil-fuel companies by other means, including pressuring financing and other institutions into restricting access to capital, bonding, and insurance, as well as pursuing tort litigation for various alleged climate-related impacts. For more information, see our Risk Factor titled “Our operations are subject to a series of risks resulting from climate change.”

Water Discharge

The CWA and similar state and local laws and regulations regulate discharges into certain waters, primarily through permitting. Section 404 of the CWA imposes permitting and mitigation requirements associated with the dredging and filling of certain wetlands and streams. The CWA and equivalent state legislation, where such equivalent state legislation exists, affect coal mining operations that impact such wetlands and streams. Although permitting requirements have been tightened in recent years, we believe we have obtained all necessary permits required under CWA Section 404 as it has traditionally been interpreted by the responsible agencies. However, mitigation requirements under existing and possible future “fill” permits may vary considerably. For that reason, the setting of post-mine asset retirement obligation accruals for such mitigation projects is difficult to ascertain with certainty and may increase in the future. For more information about asset retirement obligations, please read “Item 8. Financial Statements and Supplementary Data—Note 15 - Asset Retirement Obligations.” Although more stringent permitting requirements may be imposed in the future, we are not able to accurately predict the impact, if any, of such permitting requirements.

For us or the operators of the properties in which we hold oil & gas mineral interests to conduct certain activities, an operator may need to obtain a permit for the discharge of fill material from the Corps of Engineers and/or a discharge permit from the state regulatory authority under the state counterpart to the CWA. Our coal mining operations typically require Section 404 permits to authorize activities such as the creation of slurry ponds and stream impoundments. The CWA authorizes the EPA to review Section 404 permits issued by the Corps of Engineers, and in 2009, the EPA began reviewing Section 404 permits issued by the Corps of Engineers for coal mining in Appalachia. Currently, significant uncertainty exists regarding the obtaining of permits under the CWA for coal mining operations in Appalachia due to various initiatives launched by the EPA regarding these permits.

The EPA has authority under Section 404(c) of the Clean Water Act to prohibit, deny, restrict, or withdraw the specification of certain disposal sites for dredged or fill material if it determines that such discharges would have unacceptable adverse effects on specified resources. The EPA has initiated a Section 404(c) proceeding in connection with a proposed mining project, and related litigation remains pending. The scope and application of this authority continue to be subject to regulatory and judicial review.

States also have the ability to review the Corps of Engineers’ Section 404 permitting process, pursuant to CWA Section 401, which is also subject to ongoing litigation. In October 2021, the Northern District of California federal court vacated a 2020 rule revising the Section 401 certification process. The U.S. Supreme Court stayed this vacatur and, in September 2023, the EPA finalized its Clean Water Act Section 401 Water Quality Certification Improvement Rule, effective on November 27, 2023. The Water Quality Certification Improvement Rule was challenged by various states and a coalition of industry groups, and the challenge remains ongoing. Also, in January 2026, the EPA released a proposed rule to revise its CWA Section 401 certification rule following a May 2025 memorandum raising concerns with the existing rule implementing Section 401 promulgated in November 2023. The January 2026 proposed rule seeks to limit the scope of Section 401 reviews and clarify the regulations to ensure such reviews are completed within the one-year statutory

deadline. The proposal is not final and may be modified, challenged, or withdrawn, and any resulting rule or litigation could affect CWA Section 401 certification requirements. The full extent and impact of any such actions is unclear at this time. Any disruption in the ability to obtain required permits may result in increased costs and project delays.

TMDL regulations under the CWA establish a process to calculate the maximum amount of a pollutant that an impaired waterbody can receive and still meet state water quality standards, and to allocate pollutant loads among the point and non-point pollutant sources discharging into that water body. Likewise, when water quality in a receiving stream is better than required, states are required to conduct an antidegradation review before approving discharge permits. The adoption of new TMDL-related allocations or any changes to antidegradation policies for streams near our coal mines could require more costly water treatment and could adversely affect our coal production.

Considerable legal uncertainty exists surrounding the standard for what constitutes jurisdictional waters and wetlands subject to the protections and requirements of the CWA. The scope of federal jurisdictional reach over WOTUS under the CWA has been subject to significant uncertainty and litigation for many years. In September 2023, the EPA and the Corps of Engineers issued a final rule conforming the regulatory definition of WOTUS to the U.S. Supreme Court's 2023 decision in *Sackett v. EPA*, which narrowed the scope of federally jurisdictional waters to "relatively permanent, standing, or continuously flowing bodies of water" and wetlands with a "continuous surface connection" to such waters. However, the rule is currently subject to litigation. As a result, the September 2023 rule is currently in effect in only 24 states, and the EPA and the Corps of Engineers are using the pre-2015 definition of WOTUS in the other 26 states. In November 2025, the EPA and the Corps of Engineers issued a proposed rule to further update and narrow the definition of WOTUS. In addition, the U.S. Supreme Court's 2020 decision in *County of Maui v. Hawaii Wildlife Fund* held that, in certain cases, certain discharges from a point source to groundwater could fall within the scope of the CWA and require a permit.

Hazardous Substances and Wastes

The CERCLA, otherwise known as the "Superfund" law, and analogous state laws, impose liability, without regard to fault or the legality of the original conduct on certain classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed of or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for the release of hazardous substances may be subject to joint and several liability under CERCLA for the costs of cleaning up releases of hazardous substances and natural resource damages. Some products used in coal mining operations generate waste containing hazardous substances. We are currently unaware of any material liability associated with the release or disposal of hazardous substances from our past or present mine sites.

The RCRA and analogous state laws impose requirements for the generation, transportation, treatment, storage, disposal, and cleanup of hazardous and non-hazardous wastes. Many mining wastes are excluded from the regulatory definition of hazardous wastes, and coal mining operations covered by SMCRA permits are by statute exempted from RCRA permitting. Similarly, most wastes associated with the exploration, development, and production of oil & gas are exempt from regulation as hazardous wastes under RCRA, though these wastes typically constitute "solid wastes" that are subject to less stringent non-hazardous waste requirements. However, it is possible that RCRA could be amended or the EPA or state environmental agencies could adopt policies to require such wastes to become subject to more stringent storage, handling, treatment, or disposal requirements, which could impose significant additional costs on the operators of the properties in which we own oil & gas mineral interests. RCRA also allows the EPA to require corrective action at sites where there is a release of hazardous substances. In addition, each state has its own laws regarding the proper management and disposal of waste material. While these laws impose ongoing compliance obligations, such costs are not believed to have a material impact on our operations.

RCRA impacts the coal industry in particular because it regulates the disposal of certain CCR. On April 17, 2015, the EPA finalized regulations under RCRA for the disposal of CCR. Under the finalized regulations, CCR is regulated as "non-hazardous" waste and avoids the stricter, more costly, regulations under RCRA's "hazardous" waste rules. While the classification of CCR as a hazardous waste would have led to more stringent restrictions and higher costs, this regulation may still increase our customers' operating costs and potentially reduce their ability to purchase coal. The CCR rule was subject to legal challenge and ultimately remanded to the EPA. In May 2024, the EPA finalized changes to the CCR regulations for inactive surface impoundments at inactive electric utilities. The final rule expands the scope of impoundments subject to regulation and established groundwater monitoring, corrective action, closure, and post closure care requirements for all CCR management units. Although the rule has been challenged by industry groups, the U.S. Supreme Court rejected the challengers' request to stay the rule so the rule remains effective as promulgated. Most recently,

on February 6, 2026, EPA announced a final rule that provides additional time to meet facility evaluation requirements for identifying CCR management units and to comply with groundwater monitoring provisions. The combined effect of the CCR rules and the ELG regulations (discussed below) has compelled power generating companies to close existing ash ponds and may force the closure of certain existing coal burning power plants that cannot comply with the new standards. Such retirements may adversely affect the demand for our coal.

On November 3, 2015, the EPA published the final rule ELG, revising the regulations for the Steam Electric Power Generating category which became effective on January 4, 2016. The rule sets the first federal limits on the levels of toxic metals in wastewater that can be discharged from power plants, based on technological improvements in the steam electric power industry over the last three decades. The EPA has from time to time updated the applicable ELG regulations and most recently, in May 2024, finalized a new ELG rule applicable to steam electric power generating facilities that sets new discharge limits for flue gas desulfurization wastewater, bottom ash transport water, combustion residual leachate, and legacy wastewaters. Subsequently, in December 2025, the EPA finalized a Deadline Extensions Rule that extends certain compliance deadlines under the 2024 ELG rule and provides additional flexibilities, including updated transfer provisions and site-specific alternative compliance dates. To the extent the 2024 ELG rule, which applies to a major portion of the electric power industry, remains in effect, it may impact the market for our products.

Endangered Species Act

The federal ESA and counterpart state legislation protect species threatened with possible extinction. The USFWS works closely with the OSM and state regulatory agencies to ensure that species subject to the ESA are protected from potential impacts from mining-related and oil & gas exploration and production activities. In recent years, there has been uncertainty with respect to ESA regulation. Most recently, in November 2025, the USFWS and NMFS issued four proposed rules that would substantially revise ESA implementing regulations and largely reinstate the 2019-2020 regulatory framework under the prior Trump Administration. The proposals would modify the standards for listing and delisting species, revise the approach to designating critical habitats and amend the interagency consultation process to streamline and clarify federal review obligations. They would also restore the prior species-specific approach to protective regulations for threatened species rather than automatically applying blanket prohibitions. If the USFWS were to designate species indigenous to the areas in which we operate as threatened or endangered or to redesignate a species from threatened to endangered, we or the operators of the properties in which we hold oil & gas mineral interests could be subject to additional regulatory and permitting requirements, which in turn could increase operating costs or adversely affect our revenues.

Other Environmental, Health, and Safety Regulations

In addition to the laws and regulations described above, we are subject to regulations regarding underground and above-ground storage tanks in which we may store petroleum or other substances. Some monitoring equipment that we use is subject to licensing under the Federal Atomic Energy Act. Water supply wells located on our properties are subject to federal, state, and local regulations. In addition, our use of explosives is subject to the Federal Safe Explosives Act. We are also required to comply with the SDWA, the Toxic Substance Control Act, and the Emergency Planning and Community Right-to-Know Act. The costs of compliance with these regulations should not have a material adverse effect on our business, financial condition, or results of operations.

Human Capital

As of December 31, 2025, we employed 3,575 full-time employees, including 2,895 employees in active coal mining operations, 236 employees at Matrix Design, 237 employees supporting other operating activities, and 207 corporate employees. None of our workforce is subject to a collective bargaining agreement. Retention remains a strength across our workforce, with more than 47% of all employees serving more than five years and our typical employee has approximately four years of experience with the Partnership.

We aim to attract and retain a skilled workforce through competitive, performance-based compensation packages and comprehensive benefits. To benchmark our compensation practices, we regularly review current compensation levels for each position against peers in the coal industry and comparable sectors. Total compensation generally includes some combination of base salary, incentive compensation, health and welfare benefits and participation in our profit sharing and savings plan. Incentive compensation varies by role and may include metrics tied to production and safety goals at a

specific coal operation or broader Partnership-wide objectives. Our goal is to maintain compensation programs that are competitive in the marketplace and aligned with long-term performance and safety priorities.

Workplace safety is foundational to our culture and operations. We prioritize initiatives designed to promote employee engagement in safety processes and to drive continuous improvement. By providing a work environment that rewards safety and encourages employee participation in the safety process, we have a demonstrated history as a leader in safety performance in the coal mining industry. We are focused on improving employee safety through regular training and continuous monitoring of our progress through various industry-standard metrics. In addition, we collect respirable dust samples from the mining environment where our miners regularly work and travel, in accordance with regulatory requirements. We are also regularly inspected by MSHA. For more information about citations or orders for violations of standards under the FMSHA, as amended by the MINER Act, please see our Exhibit 95.1 to this Annual Report on Form 10-K.

We support the health and well-being of our workforce by offering medical, dental, and vision benefits for our employees. In addition, we offer on-site medical clinics at each of our coal operations and corporate offices to provide convenient access to healthcare and medical services for employees and their families. Dedicated human resources representatives are also stationed at each of our coal operations and corporate offices to assist employees with benefits, training, and other personnel-related matters. Our in-house administration of the medical plan allows us to actively manage costs while improving service delivery for employees. To date, we have been able to continue providing health and welfare benefits with no out-of-pocket premiums for our employees and 100% coverage with direct contract providers.

ITEM 1A. RISK FACTORS

Summary Risk Factors

Our business is subject to a number of risks, including risks that could prevent us from achieving our business objectives or could adversely affect our business, financial condition, results of operations, cash flows, and prospects. These risks are discussed more fully below and include but are not limited to risks related to:

Risks Inherent in an Investment in Us

- Cash distributions are not guaranteed
- Ownership of limited partner interests could be diluted
- Sales of our common units could cause decline in the market price of our common units
- Our unitholders do not elect the general partner
- The control of our general partner may be transferred to a third party
- Unitholders may be required to sell their units to our general partner
- Cost reimbursements due to our general partner could be substantial
- Your liability as a limited partner may not be limited under certain circumstances
- Our general partner's fiduciary duties are limited, and our general partner has discretion in determining the level of cash reserves and has potential conflicts of interest
- Some executive officers and directors face potential conflicts of interest

Risks Related to Our Business

- Declining global economic conditions could adversely impact us
- Financing may not be available to us on favorable terms or at all
- Our indebtedness could adversely impact us
- We depend upon the leadership of key personnel
- Legal proceedings could adversely impact us
- Our customers may not honor their contracts or may not enter into new contracts for our products
- Some of our contracts may be renegotiated or terminated
- We depend upon a few customers for significant portions of our revenues
- The credit risk of our customers could adversely impact us
- Cyber or terrorist attacks could adversely impact us
- Establishment of labor unions at our operations could adversely affect our profitability

Risks Related to Our Industries

- Changes in coal prices and/or oil & gas prices, including as a result of global geopolitical tensions, could impact our results of operations
- Competition within the coal and oil & gas industry could adversely affect our ability to sell coal
- Changes in taxes or tariffs and trade measures could adversely impact us
- Changes in consumption patterns by utilities could affect our ability to sell coal and/or impact the price of our natural gas
- Unanticipated mine operating conditions could affect our profitability
- Inability to obtain and renew permits and surety bonds necessary for operations could limit our ability to continue or expand our operations
- Fluctuations in transportation costs and availability could reduce demand for our products
- The ability to recruit, hire and retain skilled labor could impact the profitability of our operations
- Disruptions in supply chains, inflationary pressures and unexpected increases in raw material costs could impact the profitability of our operations
- Unavailability of economic coal mineral reserves and resources could limit our ability to continue or expand our operations
- Estimates of our coal mineral reserves and resources and our oil & gas reserves could be inaccurate and could result in decreased profitability
- Extensive environmental laws and regulations could reduce demand for coal as a fuel source

- Legislative and regulatory compliance is costly and could impact our business, and certain legislative and regulatory initiatives relating to our business could have negative impacts
- Mine facilities may be located in a leased portion of the surface properties which introduces a risk of disruption to our operations
- Dependency on unaffiliated operators to explore and drill on our oil & gas properties limits our ability to control the timing and quantity of production
- Delays in royalty payments, optional royalty payments and the suspension of the right to receive royalty payments could impact our business
- Availability of transportation and facilities for the products could impact our business
- Lack of hedging arrangements exposes us to the impact of commodity prices
- Expansions and acquisitions, as well as the integration of such expansions or acquisitions, have inherent risks that could adversely impact us
- Inability to obtain commercial insurance at acceptable rates could have a negative impact on our business

Tax Risks to Our Common Unitholders

- Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes, and not being subject to a material amount of entity-level taxation. Our cash available for distribution to unitholders may be substantially reduced if we become subject to entity-level taxation as a result of the IRS treating us as a corporation or legislative, judicial, or administrative changes, and may also be reduced by any audit adjustments if imposed directly on the Partnership
- Even if unitholders do not receive any cash distributions from us, unitholders will be required to pay taxes on their share of our taxable income. A unitholder's share of our taxable income may be increased as a result of the IRS successfully contesting any of the federal income tax positions we take
- Tax gain or loss on the disposition of our units could be more than expected and create tax liabilities for our unitholders
- Limitation on unitholders' ability to deduct interest expense incurred by us could create tax liabilities for our unitholders
- Tax Exempt entities and non-U.S. unitholders face unique tax issues from owning our common units that may result in adverse tax consequences for them
- IRS challenging our allocation of depreciation and amortization deductions and methods of prorating items of income, gain, loss, and deduction could cause adverse tax consequences

Risks Inherent in an Investment in Us

Cash distributions to unitholders are not guaranteed.

The payment and amount of any future distribution will be subject to the sole discretion of the Board of Directors and will depend upon many factors, including our financial condition and prospects, our capital requirements and access to financing, covenants associated with our debt obligations, and other factors that our Board of Directors may deem relevant, and there can be no assurance that we will pay a distribution in the future. The amount of cash we can distribute to holders of our common units or other partnership securities each quarter principally depends on the amount of cash we generate from our operations, which fluctuates from quarter to quarter. In addition, the actual amount of cash available for distribution may depend on other factors, including capital allocation decisions, financing availability, restrictions in debt agreements, and the amount of cash reserves, if any, established by the general partner, in its discretion, for the proper conduct of our business.

Furthermore, since the amount of cash we have available for distribution is not solely a function of profitability, which will be affected by non-cash items, we may make cash distributions during periods when we record net losses and may be unable to make cash distributions during periods when we record net income. Please read “—Risks Related to our Business” for a discussion of further risks affecting our ability to generate available cash.

We may issue an unlimited number of limited partner interests, on terms and conditions established by our general partner, without the consent of our unitholders, which will dilute your ownership interest in us and could increase the risk that we will not have sufficient available cash to make distributions.

The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit could decrease;
- the relative voting strength of each previously outstanding unit could be diminished;
- the ratio of taxable income to distributions could increase; and
- the market price of our common units could decline.

The market price of our common units could be adversely affected by sales of substantial amounts of our common units in the public markets, including sales by our existing unitholders.

The sale or disposition of a substantial number of our common units by our existing unitholders in the public markets could have a material adverse effect on the price of our common units or could impair our ability to obtain capital through an offering of equity securities. We do not know whether any such sales would be made in the public market or private placements, nor do we know what impact such potential or actual sales would have on our unit price in the future.

An increase in interest rates could cause the market price of our common units to decline.

Like all equity investments, an investment in our common units is subject to certain risks. In exchange for accepting these risks, investors may expect to receive a higher rate of return than would otherwise be obtainable from lower-risk investments. Accordingly, as interest rates rise, the ability of investors to obtain higher risk-adjusted rates of return by purchasing government-backed debt securities could cause a corresponding decline in demand for riskier investments generally, including yield-based equity investments such as publicly traded limited partnership interests. Reduced demand for our common units resulting from investors seeking other more favorable investment opportunities could cause the trading price of our common units to decline.

The credit and risk profile of our general partner and its owners could adversely affect our credit ratings and profile.

The credit and risk profile of our general partner or its owners may be factors in credit evaluations of us as a master limited partnership. This is because our general partner can exercise significant influence or control over our business activities, including our cash distribution policy, acquisition strategy, and business risk profile.

Our unitholders do not elect our general partner or vote on our general partner's officers or directors.

Unlike the holders of common stock in a corporation, our unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders did not elect our general partner and will have no right to elect our general partner on annual or other continuing bases. If our unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. Our general partner may not be removed except upon the vote of the holders of at least 66.7% of our outstanding units.

Our unitholders' voting rights are also restricted by a provision in our partnership agreement that provides that any units held by a person that owns 20.0% or more of any class of units then outstanding, other than our general partner and its affiliates, cannot be voted on any matter.

The control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest in us to a third party in a merger or a sale of its equity securities without the consent of our unitholders. Furthermore, there is no restriction in the partnership agreement on the ability of the members of our general partner to sell or transfer all or part of their ownership interest in our general partner to a third party. The new owner or owners of our general partner would then be in a position to replace the directors and officers of our general partner and control the decisions made and actions taken by the Board of Directors and officers.

Unitholders may be required to sell their units to our general partner at an undesirable time or price.

If at any time less than 20.0% of our outstanding common units are held by persons other than our general partner and its affiliates, our general partner will have the right to acquire all, but not less than all, of those units at a price no less than their then-current market price. As a consequence, a unitholder may be required to sell his common units at an undesirable time or price. Our general partner may assign this purchase right to any of its affiliates or us.

Cost reimbursements due to our general partner could be substantial and could reduce our ability to pay distributions to unitholders.

Before making any distributions to our unitholders, we will reimburse our general partner and its affiliates for all expenses they have incurred on our behalf. The reimbursement of these expenses and the payment of these fees could adversely affect our ability to make distributions to the unitholders. Our general partner has sole discretion to determine the amount of these expenses and fees. For additional information, please see “Item 13. Certain Relationships and Related Transactions, and Director Independence—Related-Party Transactions—Expense Reimbursements.”

Your liability as a limited partner may not be limited, and our unitholders could have to repay distributions or make additional contributions to us under certain circumstances.

As a limited partner in a partnership organized under Delaware law, you could be held liable for our obligations to the same extent as a general partner if you participate in the “control” of our business. Our general partner generally has unlimited liability for the obligations of the Partnership, except for those contractual obligations of the Partnership that are expressly made without recourse to our general partner. Additionally, the limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been established in many jurisdictions.

Under certain circumstances, our unitholders could have to repay amounts wrongfully distributed to them. Under Delaware law, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for three years from the date of the impermissible distribution, partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the Partnership for the distribution amount. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the Partnership are not counted for purposes of determining whether a distribution is permitted.

Our partnership agreement limits our general partner’s fiduciary duties to our unitholders and restricts the remedies available to unitholders for actions taken by our general partner that may otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that waive or consent to conduct by our general partner and its affiliates and which reduce the obligations to which our general partner would otherwise be held by state-law fiduciary duty standards. The following is a summary of the material restrictions contained in our partnership agreement on the fiduciary duties owed by our general partner to the limited partners. Our partnership agreement:

- permits our general partner to make many decisions in its “sole discretion.” This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting us, our affiliates, or any limited partner;
- provides that our general partner is entitled to make other decisions in its “reasonable discretion”;
- generally provides that affiliated transactions and resolutions of conflicts of interest not involving a required vote of unitholders must be “fair and reasonable” to us and that, in determining whether a transaction or resolution is “fair and reasonable,” our general partner may consider the interests of all parties involved, including its own. Unless our general partner has acted in bad faith, the action taken by our general partner shall not constitute a breach of its fiduciary duty; and
- provides that our general partner and our officers and directors will not be liable for monetary damages to us, our limited partners, or assignees for errors of judgment or any acts or omissions if our general partner and those other persons acted in good faith.

All limited partners are bound by the provisions in the partnership agreement, including the provisions discussed above.

Our general partner's discretion in determining the level of cash reserves may adversely affect our ability to make cash distributions to our unitholders.

Our partnership agreement requires our general partner to deduct from available cash reserves that in its reasonable discretion are necessary for the proper conduct of our business, to comply with applicable law or agreements to which we are a party, or to provide funds for future distributions to partners. These cash reserves will affect the amount of cash available for distribution to unitholders.

Our general partner has conflicts of interest and limited fiduciary responsibilities, which may permit our general partner to favor its interests to the detriment of our unitholders.

Conflicts of interest could arise in the future as a result of relationships between our general partner and its affiliates, on the one hand, and us, on the other hand. As a result of these conflicts, our general partner may favor its interests and those of its affiliates over the interests of our unitholders. The nature of these conflicts includes the following considerations:

- Remedies available to our unitholders for actions that, without the limitations, could constitute breaches of fiduciary duty are limited. Unitholders are deemed to have consented to some actions and conflicts of interest that could otherwise be deemed a breach of fiduciary or other duties under applicable state law.
- Our general partner is allowed to take into account the interests of parties in addition to us in resolving conflicts of interest, thereby limiting its fiduciary duties to our unitholders.
- Our general partner's affiliates are not prohibited from engaging in other businesses or activities, including those in direct competition with us, except as provided in the omnibus agreement (please see Exhibits 10.1 and 10.2 to this Annual Report on Form 10-K).
- Our general partner determines the amount and timing of our asset purchases and sales, capital expenditures, borrowings, and reserves, each of which can affect the amount of cash that is distributed to unitholders.
- Our general partner determines whether to issue additional units or other equity securities in us.
- Our general partner determines which costs are reimbursable by us.
- Our general partner controls the enforcement of obligations owed to us by it.
- Our general partner decides whether to retain separate counsel, accountants, or others to perform services for us.
- Our general partner is not restricted from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or from entering into additional contractual arrangements with any of these entities on our behalf.
- In some instances, our general partner may direct us to borrow funds to permit the payment of distributions.

Some of our executive officers and directors face potential conflicts of interest in managing our business.

Certain of our executive officers and directors are also officers and/or directors of AGP. These relationships could create conflicts of interest regarding corporate opportunities and other matters. The resolution of any such conflicts may not always be in our or our unitholders' best interests. These officers and directors face potential conflicts regarding the allocation of their time, which could adversely affect our business, results of operations, and financial condition.

Risks Related to Our Business

Global economic conditions or economic conditions in any of the industries in which our customers operate as well as sustained uncertainty in financial markets could have material adverse impacts on our business and financial condition that we currently cannot predict.

Weakness in global economic conditions or economic conditions in any of the industries we serve or in the financial markets could materially adversely affect our business and financial condition. For example:

- the demand for electricity in the United States and globally could decline if economic conditions deteriorate, which could negatively impact the revenues, margins, and profitability of our business;

- any inability of our customers to raise capital could adversely affect their ability to honor their obligations to us; and
- our future ability to access the capital markets could be restricted as a result of future economic conditions, which could materially impact our ability to grow our business, including the development of our coal mineral reserves and resources.

Growing our business could require significant amounts of financing that may not be available to us on acceptable terms, or at all.

We plan to fund capital expenditures for our growth initiatives with existing cash balances, future cash flows from operations, borrowings under revolving credit and securitization facilities, and cash provided from the issuance of debt or equity. At times, weakness in the energy sector in general and coal, in particular, has significantly impacted access to the debt and equity capital markets. Accordingly, our funding plans could be negatively impacted by constraints in the capital markets as well as numerous other factors, including higher than anticipated capital expenditures or lower than expected cash flow from operations. In addition, we could be unable to refinance our current debt obligations when they expire or obtain adequate funding prior to expiry because our lending counterparties may be unwilling or unable to meet our funding needs. Furthermore, additional growth projects and expansion opportunities could develop in the future that could also require significant amounts of financing that may not be available to us on acceptable terms or in the amounts we expect, or at all.

Various factors could adversely impact the debt and equity capital markets as well as our credit ratings or our ability to remain in compliance with the financial covenants under our then-current debt agreements, which in turn could have a material adverse effect on our financial condition, results of operations, and cash flows. If we are unable to finance our growth initiatives as expected, we could be required to seek alternative financing, the terms of which may not be attractive to us, or to revise or cancel our plans.

Our indebtedness could limit our ability to borrow additional funds, make distributions to unitholders, or capitalize on business opportunities.

We had long-term indebtedness of \$463.5 million as of December 31, 2025. Our leverage may:

- adversely affect our ability to finance future operations and capital needs;
- limit our ability to pursue acquisitions and other business opportunities;
- make our results of operations more susceptible to adverse economic or operating conditions; and
- make it more difficult to self-insure for our workers' compensation or black lung obligations or post collateral security therefor.

In addition, we have unused borrowing capacity under our Revolving Credit Facility. Future borrowings, under our credit facilities or otherwise, could increase our leverage.

Our payments of principal and interest on any indebtedness will reduce the cash available for distribution on our units. We will be prohibited from making cash distributions:

- during an event of default under any of our indebtedness; or
- if after such distribution, we fail to meet a coverage test based on the ratio of our consolidated cash flow to our consolidated fixed charges.

Various limitations in our debt agreements may reduce our ability to incur additional indebtedness, engage in some transactions, and capitalize on business opportunities, including the sale or disposition of certain of our mineral assets. For example, if prior to June 15, 2026, a Specified Minerals Disposition (as defined in the indenture governing the 2029 Senior Notes and which involves our oil and gas mineral interests) occurs, we will be required to make an offer to purchase up to 40% of the aggregate principal amount of 2029 Senior Notes.

Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions. Please see "Item 8. Financial Statements and Supplementary Data—Note 6 – Long-Term Debt" for further discussion.

We depend on the leadership and involvement of Joseph W. Craft III and other key personnel for the success of our business.

We depend on the leadership and involvement of Mr. Craft. Mr. Craft has been integral to our success, due in part to his ability to identify and develop internal growth projects and accretive acquisitions, make strategic decisions, and attract and retain key personnel. The loss of his leadership and involvement or the services of any members of our senior management team could have a material adverse effect on our business, financial condition, and results of operations.

We and our subsidiaries are subject to various legal proceedings, which could have a material adverse effect on our business.

We are party to a number of legal proceedings incident to our normal business activities. There is the potential that an individual matter or the aggregation of multiple matters could have an adverse effect on our cash flows, results of operations, or financial position. Please see “Item 3. Legal Proceedings” and “Item 8. Financial Statements and Supplementary Data—Note 16 – Commitments and Contingencies” for further discussion.

The stability and profitability of our operations could be adversely affected if our customers do not honor existing contracts or do not extend existing or enter into new long-term contracts for coal.

In 2025, we sold approximately 84.6% of our coal sales tonnage under contracts having a term greater than one year, which we refer to as long-term sales contracts. These contracts have historically provided a relatively secure market for the production committed under the terms of the contracts. From time to time industry conditions could make it more difficult for us to enter into long-term sales contracts with our electric utility customers, and if supply exceeds demand in the coal industry, electric utilities may become less willing to lock in price or quantity commitments for an extended period of time. Accordingly, we may not be able to continue to obtain long-term sales contracts with reliable customers as existing contracts expire, which could subject a portion of our revenue stream to the increased volatility of the spot market.

Some of our long-term sales contracts contain provisions allowing for the renegotiation of prices and, in some instances, the termination of the contract or the suspension of purchases by customers.

Some of our long-term sales contracts contain provisions that allow the purchase price to be renegotiated at periodic intervals. These price reopener provisions may automatically set a new price based on the prevailing market price or, in some instances, require the parties to the contract to agree on a new price. Any adjustment or renegotiation leading to a significantly lower contract price could adversely affect our operating profit margins. Accordingly, long-term sales contracts may provide only limited protection during adverse market conditions. In some circumstances, the failure of the parties to agree on a price under a reopener provision can also lead to the early termination of a contract.

Several of our long-term sales contracts also contain provisions that allow the customer to suspend or terminate performance under the contract upon the occurrence or continuation of certain events that are beyond the customer’s reasonable control. Such events could include labor disputes, mechanical malfunctions, and changes in government regulations, including changes in environmental regulations rendering the use of our coal inconsistent with the customer’s environmental compliance strategies. Additionally, most of our long-term sales contracts contain provisions requiring us to deliver coal within stated ranges for specific coal characteristics. Failure to meet these specifications can result in economic penalties, rejection or suspension of shipments, or termination of the contracts. In the event of early termination of any of our long-term sales contracts, if we are unable to enter into new contracts on similar terms, our business, financial condition, and results of operations could be adversely affected.

We depend on a few customers for a significant portion of our revenues, and the loss of one or more significant customers could affect our ability to maintain the sales volume and price of the coal we produce.

In 2025, we derived more than 10% of our total revenues from each of Louisville Gas and Electric Company and American Electric Power Company, Inc. If we were to lose this or any of our significant customers without finding replacement customers willing to purchase an equivalent amount of coal on similar terms, or if these customers were to decrease the amounts of coal purchased or change the terms, including pricing terms, on which they buy coal from us, it could have a material adverse effect on our business, financial condition, and results of operations.

Our ability to collect payments from our customers could be impaired if their creditworthiness declines or if they fail to honor their contracts with us.

Our ability to receive payment for coal sold and delivered depends on the continued creditworthiness of our customers. If the creditworthiness of our customers declines significantly, our business could be adversely affected. In addition, if a customer refuses to accept shipments of our coal for which they have an existing contractual obligation, our revenues will decrease and we may have to reduce production at our mines until our customer's contractual obligations are honored.

Terrorist attacks or cyber incidents could result in information theft, data corruption, operational disruption, and/or financial loss.

Like most companies in our industry, we have become increasingly dependent upon access to and the use of our digital technologies, including information systems, infrastructure, and cloud applications and services, to operate our businesses, process and record financial and operating data, communicate with our business partners, analyze mine and mining information, and estimate quantities of reserves and resources, as well as other activities related to our businesses. We also depend on the information systems and infrastructure of third-party vendors, contractors, and partners to support various aspects of our operations. Additionally, certain networks and systems are managed by external service providers which operate outside our direct control. This reliance introduces risks, including potential system failures, security breaches, and external attacks. Strategic targets, such as energy-related assets, could be at greater risk of future terrorist or cyber-attacks than other targets in the United States.

Deliberate attacks, natural disasters, user error, or other security breaches or failures in, on or to our systems or infrastructure, or the systems or infrastructure of third parties on whom we rely could lead to the unauthorized access to, unauthorized disclosure of, restricted access to, or corruption or loss of our proprietary data and potentially sensitive data, including data related to personal information, critical operations and financial records. We have in the past been, and may in the future be, subject to cyber incidents, along with our third-party vendors, contractors and partners. Such incidents may also result in disruptions to critical systems, data corruption, delays in production or delivery, difficulty in completing and settling transactions, misdirected wire transfers, challenges in maintaining our books and records, environmental damage, communication interruptions, increased safety risk for personnel, other operational disruptions, and third-party liability. Additionally, we may face regulatory scrutiny or penalties resulting from data privacy or cybersecurity violations in the aftermath of such incidents. The expanding regulatory framework for data protection increases the challenges of securing our information. Adhering to these changing requirements could cause us to incur substantial costs, and any real or perceived non-compliance may lead to regulatory penalties, legal action, and damage to our reputation.

While we maintain insurance, our insurance may not adequately protect us against all damages as a result of these occurrences. Consequently, it is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition, results of operations, cash flows and reputation. Although we have implemented and maintain commercially reasonable security controls including by implementing detection and prevention systems, regular cybersecurity assessments, employee training programs, and incident response plans, there are no guarantees that these will be successful in preventing security threats from materializing, detecting such threats, or mitigating their impact. As cybersecurity threats grow increasingly more sophisticated, the risk of successful breaches, disruptions, or vulnerabilities persists despite our proactive efforts and we could be required to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents. While we have not experienced significant losses from cyberattacks so far and take steps to address emerging threats, no security system offers complete protection. Such incidents could lead to the loss of sensitive information or critical resources, regulatory penalties, reputational damage, data privacy liabilities, and substantial costs for remediation and system upgrades, all of which could have a material adverse impact on our reputation, financial position, operations, and cash flows.

We face various risks related to pandemics and similar outbreaks, which have had and may in the future have material adverse effects on our business, financial position, results of operations, and/or cash flows.

Pandemics, outbreaks or other public health events that are outside of our control could significantly disrupt our operations and adversely affect our financial condition. The global or national outbreak of an illness or other communicable disease or any other public health crisis may cause disruptions to our business and operations, which may include (i) shortages of employees, (ii) unavailability of contractors or subcontractors, (iii) interruption of supplies from third parties upon which we rely, (iv) restrictions recommended or imposed by government and health authorities, including

quarantines, to address an outbreak and (v) restrictions that we and our contractors, subcontractors and our customers impose, including facility shutdowns, to ensure the safety of employees.

The extent to which any future pandemic may adversely impact our results of operations, cash flows and financial condition depends on future developments, which are highly uncertain and unpredictable.

Although none of our employees are members of unions, our workforce may not remain union-free in the future.

None of our employees are represented under collective bargaining agreements. However, our workforce may not remain union-free in the future, and legislative, regulatory, or other governmental action could make it more difficult to remain union-free. If some or all of our currently union-free operations were to become unionized, it could adversely affect our productivity and increase the risk of work stoppages at our mining complexes. In addition, even if we remain union-free, our operations could still be adversely affected by work stoppages at unionized companies, particularly if union workers were to orchestrate boycotts against our operations.

Risks Related to Our Industries

Prices for oil & gas, as well as coal, are volatile and can fluctuate widely based on a number of factors beyond our control. An extended decline in the prices of such commodities could negatively impact our results of operations.

Our results of operations are primarily dependent upon the prices of oil & gas and coal, as well as our ability to improve productivity and control costs. The prices for oil & gas and coal depend upon factors beyond our control, including:

- overall domestic and global economic conditions;
- the supply of and demand for domestic and foreign coal;
- the supply of and demand for oil & gas;
- weather conditions and patterns that affect demand for coal and oil & gas, or our ability to produce coal or the ability of operators to produce oil & gas from our mineral interests;
- supply chain and cost of raw materials for coal and oil & gas operations;
- the adverse impact of pandemics, outbreaks and other public health events;
- the proximity to and capacity of transportation facilities;
- competition from other coal suppliers;
- domestic and foreign governmental regulations and taxes;
- the price and availability of alternative fuels;
- the effect of worldwide energy consumption, including the impact of technological advances on energy consumption;
- international developments impacting the supply of coal;
- international developments impacting the supply of oil & gas; and
- the impact of domestic and foreign governmental laws and regulations.

Any adverse change in these factors could result in weaker demand and lower prices for our products. A substantial or extended decline in coal prices could materially and adversely affect us by decreasing our revenues to the extent we are not protected by the terms of existing coal supply agreements.

Competition within the coal industry could adversely affect our ability to sell coal. In addition, foreign currency fluctuations could adversely affect the competitiveness of our coal abroad.

We compete with other coal producers in various regions of the United States for domestic coal sales. In addition, we face competition from foreign and domestic producers that sell their coal in the international coal markets. The most important factors on which we compete are delivered price (*i.e.*, the cost of coal delivered to the customer, including transportation costs, which are generally paid by our customers either directly or indirectly), coal quality characteristics, contract flexibility (*e.g.*, volume optionality and multiple supply sources), and reliability of supply. Some competitors could have, among other things, larger financial and operating resources, lower per ton cost of production, or relationships with specific transportation providers. The competition among coal producers could impact our ability to retain or attract customers and could adversely impact our revenues and cash available for distribution.

We sell coal in the export thermal and metallurgical coal market, both of which are significantly affected by international demand and competition. Consolidation in the coal industry or current or future bankruptcy proceedings of coal competitors could adversely affect us. The prices of and demand for our coal could significantly decline, which could have a material adverse effect on our business, financial condition, results of operations, and cash flows, and could reduce our revenues and cash available for distribution.

In addition, we face competition from foreign producers that sell their coal in the export market. Potential changes to international trade agreements, trade concessions, or other political and economic arrangements could benefit coal producers operating in countries other than the United States. We could be adversely impacted on the basis of price or other factors by foreign trade policies or other arrangements that benefit competitors. In addition, we periodically sell our coal internationally in United States dollars and, as a result, general economic conditions in foreign markets and changes in foreign currency exchange rates could provide our foreign competitors with a competitive advantage. If our competitors' currencies decline against the United States dollar or foreign purchasers' local currencies, those competitors could be able to offer lower prices for coal to those purchasers. Furthermore, if the currencies of overseas purchasers were to significantly decline in value in comparison to the United States dollar, those purchasers may seek decreased prices for the coal we sell. Consequently, currency fluctuations could adversely affect the competitiveness of our coal in international markets, which could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

Changes in taxes or tariffs and other trade measures by the United States and foreign governments could adversely affect our results of operations, financial position, and cash flows.

We pay certain taxes and fees related to our operations. Congress or state legislatures may seek to increase these taxes and fees that relate specifically to the coal industry. We cannot predict further developments, and such increases could have a material adverse effect on our results of operations, financial position, and cash flows.

New tariffs and other trade measures could adversely affect our results of operations, financial position, and cash flows. In response to tariffs imposed by the United States, several countries have imposed tariffs on United States goods and services, including coal. These tariffs, along with any additional tariffs or trade restrictions that may be implemented by the United States or retaliatory trade measures or tariffs implemented by other countries, could result in reduced economic activity, increased costs in operating our business, reduced demand and changes in purchasing behaviors for thermal and metallurgical coal, limits on trade with the United States or other potentially adverse economic outcomes. Additionally, we sell coal into the export thermal and metallurgical markets. Accordingly, our international sales could also be impacted by the tariffs and other restrictions on trade between the United States and other countries. We cannot predict the impact that new or changes in tariffs and other trade measures imposed by the United States or other countries on United States goods, but such new or changes in trade measures could have a material adverse effect on our results of operations, financial position and cash flows and could reduce our revenues and cash available for distribution. Please see risk factor titled "Unexpected increases in raw material costs could significantly impair our operating profitability." for additional information.

Global geopolitical tensions have caused, and may cause in the future, significant market disruptions that may lead to increased volatility in the price of commodities, including oil & gas, coal, and other sources of energy.

Volatility in coal and oil & gas prices has been and may continue to be heightened as a result of the Russian-Ukrainian conflict, hostilities in the Middle East and the potential impact to global shipping and the evolving situation in Venezuela. These events have caused volatility in the aforementioned commodity markets. Such conflicts and the resulting volatility may significantly affect prices for our coal and oil & gas or the cost of supplies and equipment, as well as the prices of competing sources of energy for our electric power plant customers.

Global geopolitical conflicts, trade and monetary sanctions, as well as any escalation of the conflict and future developments, could significantly affect worldwide market prices and demand for our coal and oil & gas and cause turmoil in the capital markets and generally in the global financial system. Additionally, the geopolitical and macroeconomic consequences of such conflicts and any associated sanctions cannot be predicted but could severely impact the world economy. If any of these events occur, the resulting political instability and societal disruption could reduce overall demand for products, causing a reduction in our revenues or an increase in our costs and thereby materially and adversely affecting our results of operations.

Changes in consumption patterns by utilities regarding the use of coal, including plans by utilities to shut down or move away from coal-fired generation, have affected our ability to sell the coal we produce and may do so in the future.

Our business is closely linked to the demand for electricity, and any changes in coal consumption by domestic or international electric power generators would likely impact our business over the long term. The domestic electric power sector accounts for the vast majority of the total domestic coal consumption. The amount of coal consumed by the domestic electric utility industry is affected primarily by the overall demand for electricity, environmental and other governmental regulations, and the price and availability of competing fuels for power plants such as nuclear, natural gas, and fuel oil as well as alternative sources of energy. Our primary competition is from natural gas-fired plants that are relatively more efficient and less difficult to permit than coal-fired plants.

Future environmental regulation of GHG emissions also could accelerate the use by utilities of fuels other than coal. In addition, federal and state mandates for increased use of electricity derived from renewable energy sources could affect demand for coal. Such mandates, combined with other incentives to use renewable energy sources such as tax credits, could make alternative fuel sources more competitive with coal. Further, far-reaching federal regulations promulgated by the EPA in the last several years, such as MATS, have in the past led to the retirement of coal-fired generating units and a significant reduction in the amount of coal-fired generating capacity in the United States. A decrease in coal consumption by the domestic electric utility industry could adversely affect the demand for or the price of coal, which could negatively impact our results of operations and reduce our cash available for distribution.

Other factors, such as efficiency improvements associated with technologies powered by electricity have slowed electricity demand growth in the past, and while demand growth has grown in recent years in the U.S., could contribute to slower growth in the future. Further decreases in the demand for electricity, such as decreases that could be caused by a worsening of current economic conditions, could have a material adverse effect on the demand for coal and our business over the long term.

We, our customers, or the operators of our oil & gas mineral interests could be subject to litigation or regulatory fines or penalties related to climate change.

Increased attention to climate change risk has also resulted in governmental investigations and private litigation by state and local governmental agencies as well as private plaintiffs in an effort to hold energy companies accountable for the alleged effects of climate change. Other public nuisance lawsuits have been brought in the past against power, coal, and oil & gas companies alleging that their operations are contributing to climate change. The plaintiffs in these suits sought various remedies, including punitive and compensatory damages and injunctive relief. While the U.S. Supreme Court held that federal common law provided no basis for public nuisance claims against the defendants in those cases, tort-type liabilities remain a possibility and a source of concern. Government entities in other states (including California and New York) have brought similar claims seeking to hold a wide variety of companies that produce fossil fuels liable for the alleged impacts of the GHG emissions attributable to those fuels. Those lawsuits allege damages as a result of climate change and the plaintiffs are seeking unspecified damages and abatement under various tort theories. Separately, litigation has been brought against certain fossil-fuel companies alleging that they have been aware of the adverse effects of climate change for some time but failed to adequately disclose such impacts to their investors or consumers. In addition, in December 2024, New York adopted a law requiring companies that emitted over one billion tons of GHG emissions into the atmosphere between 2000 and 2018, with sufficient connections to the state, to pay into a “climate superfund” to support climate-related adaptation and mitigation projects. We, among others, have been identified by New York as a potentially responsible party under the law but, to date, have not received any cost recovery demands. The law has been challenged by the Department of Justice pursuant to an Executive Order and the litigation remains pending at this time. It is uncertain whether we or others in our industry will ultimately be required to pay penalties as a result of the New York law, nor can we predict whether or not other states will adopt similar legislation in the future. To the extent we are required to pay such penalties, they could have a material adverse effect on our business, financial condition and results of operations. It is possible that we could be included in similar future lawsuits initiated by state and local governments as well as private claimants or subject to regulatory fines or penalties in the future.

Continued attention to sustainability matters may negatively impact our business, financial results, and unit price.

Companies across all industries, including companies in fossil-fuel industries, have faced increased scrutiny from stakeholders related to their sustainability practices in the past. Companies that did not adapt or comply with evolving

investor or stakeholder expectations and standards, or were perceived to have not responded appropriately to sustainability issues, regardless of any legal requirement to do so, might have suffered reputational damage and the business, financial condition, and valuation of such companies could have been adversely affected. Several advocacy groups, both domestically and internationally, have campaigned for governmental and private action to promote change at public companies related to sustainability matters, including through the investment and voting practices of investment advisers, public pension funds, universities, and other members of the investing community. These activities include increased attention to and demands for action related to climate change, changes in regulation relating to climate change, promoting the use of substitutes to fossil-fuel products, encouraging the divestment of fossil-fuel equities, and pressuring lenders to limit funding to companies engaged in the extraction of fossil-fuel reserves. These activities could increase costs, reduce demand for our coal and hydrocarbon products, reduce our profits, increase the potential for investigations and litigation, impair our brand, limit our choices for lenders, insurance providers and business partners, and have negative impacts on our unit price and access to capital markets.

Investors', lenders' and other stakeholders' focus on sustainability-related metrics have increased and waned over time, in particular as governmental administrations both domestic and international change from time to time. Companies in general have received pressure from investors, lenders or other stakeholders to adopt climate or other sustainability-related metrics, and to the extent that those pressures impact the fossil fuel industry and, in particular, the coal industry as investors', lenders' and other stakeholders' sentiments regarding sustainability change over time, we cannot guarantee that we will be able to meet such metrics because of potential costs, inaccurate assumptions or technical or operational obstacles. A failure or a perception of failure (whether or not valid) to pursue, implement or make progress against such metrics could result in governmental investigations or enforcement, private litigation and damage our reputation, cause our investors or consumers to lose confidence in us, and negatively impact our operations.

Certain organizations that provide sustainability and other corporate risk information and ratings to investors and unitholders have developed processes to evaluate companies and investment funds based on "sustainability" metrics. Currently, there are no universal standards for such scores or ratings, but consideration of sustainability evaluations has become more broadly accepted by some investors in the past. Such assessments were used by some investors to inform their investment decisions. Companies in the energy industry, and in particular those focused on coal, natural gas, or oil extraction, often do not fare as well under sustainability assessments compared to companies in other industries. Consequently, a low sustainability assessment could result in our securities, both debt and equity, being excluded from the portfolios of certain investment funds and investors, restricting our access to insurance or capital to fund our continuing operations and growth opportunities. Additionally, to the extent sustainability matters negatively impact our reputation, we may not be able to compete as effectively to recruit or retain employees, which may adversely affect our operations.

Certain public statements with respect to sustainability matters have been in the past subject to heightened scrutiny from public and governmental authorities, as well as other parties, related to the risk of potential "greenwashing," i.e., misleading information or false claims overstating potential sustainability benefits. Certain regulators, such as the SEC (particularly under past presidential administrations) and various state agencies, as well as non-governmental organizations and other private actors have also filed lawsuits under various securities and consumer protection laws alleging that certain sustainability statements, emission reduction claims, approaches to accounting for GHG emissions reductions or other sustainability-related goals, or standards were misleading, false, or otherwise deceptive. Any alleged claims of greenwashing against us or others in our industry may lead to further negative sentiment and diversion of investments. Additionally, we could face increasing costs as we attempt to comply with and navigate further sustainability-related focus and scrutiny.

Additionally, certain employment or business practices and social initiatives are the subject of scrutiny by both those calling for the continued advancement of such policies, as well as those who believe they should be curbed, including government actors, and the complex regulatory and legal frameworks applicable to such initiatives continue to evolve. We cannot be certain of the impact of such regulatory, legal and other developments on our business.

Litigation resulting from disputes with our customers could result in substantial costs, liabilities, and loss of revenues.

From time to time, we have disputes with our customers over the provisions of coal supply contracts relating to, among other things, coal pricing, quality, quantity, and the existence of specified conditions beyond our or our customers' control that suspend performance obligations under the particular contract. Disputes could occur in the future and we may not be

able to resolve those disputes in a satisfactory manner, which could have a material adverse effect on our business, financial condition, and results of operations.

Our profitability could decline due to unanticipated mine operating conditions and other events that are not within our control and that may not be fully covered under our insurance policies.

Our coal mining operations are influenced by changing conditions or events that can affect production levels and costs at particular mines for varying lengths of time and, as a result, can diminish our profitability. These conditions and events include, among others:

- mining and processing equipment failures and unexpected maintenance problems;
- unavailability of required equipment;
- prices for fuel, steel, explosives, and other supplies;
- fines and penalties incurred as a result of alleged violations of environmental and safety laws and regulations;
- variations in the thickness of the layer, or seam, of coal;
- amounts of overburden, partings, rock, and other natural materials;
- weather conditions, such as heavy rains, flooding, ice, and other natural events affecting operations, transportation, or customers;
- accidental mine water discharges and other geological conditions;
- fires;
- seismic activities, ground failures, rock bursts or structural cave-ins or slides;
- employee injuries or fatalities;
- labor-related interruptions;
- increased reclamation costs;
- inability to acquire, maintain or renew mining rights or permits in a timely manner, if at all;
- fluctuations in transportation costs and the availability or reliability of transportation;
- new or changes in legislation or regulations that have the effect of increasing our operating costs; and
- unexpected operational interruptions due to other factors.

These conditions have the potential to significantly impact our operating results. Prolonged disruption of production at any of our mines would result in a decrease in our revenues and profitability, which could materially adversely impact our quarterly or annual results.

Effective October 1, 2025, we renewed our property and casualty insurance program through September 30, 2026. Our property insurance was procured from our wholly owned captive insurance company, Wildcat Insurance. Wildcat Insurance charged certain of our subsidiaries for the premiums on this program and in return purchased reinsurance for the program in the standard market. The maximum limit in the commercial property program is \$100.0 million per occurrence, excluding a \$1.5 million deductible for property damage, a 75- or 90-day waiting period for underground business interruption depending on the mining complex and an additional \$25.0 million overall aggregate deductible. We retained a 2.50% participating interest in our current commercial property insurance program. We can make no assurances that we will not experience significant insurance claims in the future that could have a material adverse effect on our business, financial condition, results of operations and ability to purchase property insurance in the future. Also, exposures exist for which no insurance may be available and for which we have not reserved. In addition, the insurance industry has been subject to efforts by environmental activists to restrict coverages available for fossil-fuel companies.

We could be unable to obtain and renew permits necessary for our coal mining operations, which could reduce our production, cash flow, and profitability.

Mining companies must obtain numerous governmental permits or approvals that impose strict conditions and obligations relating to various environmental and safety matters in connection with coal mining. The permitting rules are complex and can change over time. Regulatory authorities exercise considerable discretion in the timing and scope of permit issuance. The public has the right to comment on permit applications and otherwise participate in the permitting process, including through court intervention. Accordingly, permits required to conduct our operations may not be issued, maintained, or renewed, may not be issued or renewed in a timely fashion, or may involve requirements that restrict our ability to economically conduct our mining operations. Limitations on our ability to conduct our mining operations due to the inability to obtain or renew necessary permits or similar approvals could reduce our production, cash flow, and

profitability. Please read “Item 1. Business—Environmental, Health and Safety Regulations—*Mining Permits and Approvals*.”

The EPA has been reviewing permits required for the discharge of overburden from mining operations under Section 404 of the CWA. Various initiatives by the EPA regarding these permits have increased the time required to obtain and the costs of complying with such permits. In addition, the EPA previously exercised its “veto” power to withdraw or restrict the use of previously issued permits in connection with one of the largest surface mining operations in Appalachia. The EPA’s action was ultimately upheld by a federal court. As a result of these developments, we could be unable to obtain or experience delays in securing, utilizing, or renewing Section 404 permits required for our operations, which could have an adverse effect on our results of operation and financial position. Please read “Item 1. Business—Environmental, Health and Safety Regulations—*Water Discharge*.”

In addition, some of our permits could be subject to challenges from the public, which could result in additional costs or delays in the permitting process or even an inability to obtain permits, permit modifications, or permit renewals necessary for our operations.

Fluctuations in transportation costs and the availability or reliability of transportation could reduce revenues by causing us to reduce our production or by impairing our ability to supply coal to our customers.

Transportation costs represent a significant portion of the total cost of coal for many of our customers and, as a result, the cost of transportation is a critical factor in a customer’s purchasing decision. Increases in transportation costs could make coal a less competitive source of energy or could make our coal production less competitive than coal produced from other sources. Disruption of transportation services due to weather-related problems, flooding, drought, accidents, mechanical difficulties, strikes, lockouts, bottlenecks, or other events could temporarily impair our ability to supply coal to our customers. Our transportation providers could face difficulties in the future that could impair our ability to supply coal to our customers, resulting in decreased revenues. If there are disruptions in the transportation services provided by our primary rail or barge carriers that transport our coal and we are unable to find alternative transportation providers to ship our coal, our business could be adversely affected.

States in which our coal is transported by truck may modify or increase enforcement of their laws regarding weight limits or coal trucks on public roads. Such legislation and enforcement efforts could result in shipment delays and increased costs. An increase in transportation costs could have an adverse effect on our ability to increase or maintain production and could adversely affect revenues.

Political or financial instability, currency fluctuations, the outbreak of pandemics or other illnesses (such as the COVID-19 pandemic), labor unrest, transport capacity and costs, port security, weather conditions, natural disasters, or other events that could alter or suspend our operations, slow or disrupt port activities, or affect foreign trade are beyond our control and could materially disrupt our ability to participate in the export market for coal sales, which could adversely affect our sales and our results of operations.

Increases in raw material costs could significantly impair our operating profitability.

Our coal mining operations are affected by commodity prices. We use significant amounts of steel, petroleum products, and other raw materials in various pieces of mining equipment, supplies, and materials, including the roof bolts required by the room-and-pillar method of mining. Steel prices and the prices of scrap steel, natural gas, and coking coal consumed in the production of iron and steel fluctuate significantly and could change unexpectedly. Inflationary pressures, including as a result of the imposition or increase of existing tariffs, have and could continue to lead to price increases affecting many of the components of our operating expenses such as fuel, steel, and maintenance expenses. For example, on March 12, 2025, the U.S. government imposed a 25% tariff on steel imports, which was increased to 50% on June 4, 2025, and on April 2, 2025, the U.S. government announced a 10% tariff on product imports from almost all foreign countries and individualized higher tariffs on certain other countries. The U.S. government announced on February 20, 2026, that it would maintain the near global tariff under another statutory authority but will increase the tariff to 15%. Several tariff announcements have been followed by announcements of limited exemptions and temporary pauses. These actions have caused uncertainty and volatility in financial markets and may result in retaliatory measures on U.S. goods. While the ultimate impact of these tariffs is unknown at this time, a portion of our coal production is used by end users to produce steel, and we use a significant amount of steel in our own operations. To the extent that such tariffs depress demand for steel globally or increase the cost to purchase steel, our results of operations, financial position and cash flows may be materially and adversely effected. There could be acts of nature or terrorist attacks or threats that could also impact the future costs of raw materials. Future volatility in the price of steel, petroleum products, or other raw materials will impact our operational expenses and could result in significant fluctuations in our profitability.

A shortage of skilled labor may make it difficult for us to maintain labor productivity and competitive costs and could adversely affect our profitability.

Efficient coal mining using modern techniques and equipment requires skilled laborers, preferably with at least one year of experience and proficiency in multiple mining tasks. In recent years, a shortage of experienced coal miners has caused us to pay more in direct labor costs in our efforts to attract and maintain talent, and to include some inexperienced staff in the operation of certain mining units, which decreases our productivity and increases our costs. This shortage of experienced coal miners is the result of a significant percentage of experienced coal miners reaching retirement age, combined with the difficulty of retaining existing workers and attracting new workers to the coal industry. Thus, this shortage of skilled labor could continue over an extended period. If the shortage of experienced labor continues or worsens, it could have an adverse impact on our labor productivity and costs and our ability to expand production in the event there is an increase in the demand for our coal, which could adversely affect our profitability.

Disruptions in supply chains, inflationary pressures and unexpected increases in raw material costs could significantly impair our operating profitability.

We are dependent upon vendors to supply mining equipment, safety equipment, supplies, and materials. If a vendor fails to deliver on its commitments, or if common carriers have difficulty providing capacity to meet demand for their services, we could experience reductions in our production or increased production costs, which could lead to reduced profitability and adversely affect our results of operations.

Inflationary pressures could significantly impair our operating profitability.

Certain countries have experienced and could in the future experience substantial, and in some periods extremely high, rates of inflation. Inflation and rapid fluctuations in inflation rates have had and may continue to have negative effects on the economies of certain countries, including the United States. Inflation rates may continue to increase in the future, and government measures to control inflation, adopted presently or in the future, remain uncertain. Measures taken by the governments to control inflation potentially include maintaining a tight monetary policy with high interest rates, thereby restricting the availability of credit and hindering economic growth. Inflation, measures to combat inflation and public speculation about possible additional actions have contributed materially to economic uncertainty in many countries. Any future inflationary or deflationary pressures could adversely affect the results of our operations. For example, at times our results have been significantly impacted by price increases affecting many of the components of our operating expenses such as fuel, steel, maintenance expenses and labor. In addition to potential cost increases, inflation could cause a decline in global or regional economic conditions that reduces demand for our coal or oil & gas and could adversely affect our results of operations.

The unavailability of an adequate supply of coal mineral reserves and resources that can be mined at competitive costs could cause our profitability to decline.

Our profitability depends substantially on our ability to mine coal mineral reserves and resources that have the geological characteristics that enable them to be mined at competitive costs and to meet the quality needed by our customers. Because we deplete our reserves and resources as we mine coal, our future success and growth depend, in part, upon our ability to acquire additional coal mineral reserves and resources that are economically recoverable. Replacement reserves and resources may not be available when required or, if available, may not be mineable at costs comparable to those of the depleting mines. We may not be able to accurately assess the geological characteristics of any reserves or resources that we acquire, which could adversely affect our profitability and financial condition. Exhaustion of reserves and resources at certain mines also could have an adverse effect on our operating results that is disproportionate to the percentage of overall production represented by such mines. Our ability to obtain other reserves and resources in the future could be limited by restrictions under our existing or future debt agreements, competition from other coal companies for attractive properties, the lack of suitable acquisition candidates, or the inability to acquire coal properties on commercially reasonable terms.

The estimates of our coal mineral reserves and resources could prove inaccurate and could result in decreased profitability.

The estimates of our coal mineral reserves and resources could vary substantially from the actual amounts of coal we are able to economically recover. The reserve and resource data set forth in “Item 2. Properties—Coal Mineral Resources and Reserves” represent engineering estimates. All of the coal mineral reserves presented in this Annual Report on Form 10-K constitute proven and probable mineral reserves. There are numerous uncertainties inherent in estimating quantities of reserves and resources, including many factors beyond our control. Estimates of coal mineral reserves and resources necessarily depend upon a number of variables and assumptions, any one of which could vary considerably from actual results. These factors and assumptions relate to:

- geological and mining conditions, which may not be fully identified by available exploration data and/or differ from our experiences in areas where we currently mine;
- the percentage of coal in the ground ultimately recoverable;
- historical production from the area compared with production from other producing areas;
- the assumed effects of regulation and taxes by governmental agencies;
- future improvements in mining technology; and
- assumptions concerning future coal prices, operating costs, capital expenditures, severance and excise taxes, and development and reclamation costs.

Each of the factors which impacts reserve and resource estimation may vary considerably from the assumptions used in making the estimation and, as a result, the estimates in this report may not accurately reflect our actual coal reserves and resources. Actual production, revenues and expenditures with respect to our coal reserves will likely vary from the assumptions used in these estimates, and these variances may be material. Government regulations and other pressures may result in the closure of coal-fired electric generating plants earlier than assumed. Such changes would reduce the economic viability of our mining operations and could have a material adverse impact on our operations and financial results.

Coal mining in certain areas in which we operate is more difficult and involves more regulatory constraints than mining in other areas of the United States, which could affect the mining operations and cost structures of these areas.

The geological characteristics of some of our coal mineral reserves, such as depth of overburden and coal seam thickness, make them difficult and costly to mine. As mines become depleted, replacement reserves may not be available when required or, if available, may not be mineable at costs comparable to those of the depleting mines. In addition, permitting, licensing, and other environmental and regulatory requirements associated with certain of our mining operations are more costly and time-consuming to satisfy. Subsidence issues are particularly important to our operations engaged in longwall mining. Failure to timely and economically secure subsidence rights or any associated mitigation agreements could materially affect our results by causing delays or changes in our mining plan. These factors could materially adversely affect the mining operations and cost structures of, and our customers’ ability to use coal produced by, our mines.

Extensive environmental laws and regulations affect coal consumers and could affect the demand for coal as a fuel source.

Federal, state, and local laws and regulations extensively regulate the amount of sulfur dioxide, particulate matter, nitrogen oxides, mercury, and other compounds emitted into the air from coal-fired electric power plants, which are the ultimate consumers of much of our coal. These laws and regulations can require significant emission control expenditures for many coal-fired power plants, and various new and proposed laws and regulations could require further emission reductions and associated emission control expenditures. These laws and regulations could affect demand and prices for coal. There is also continuing pressure on federal and state regulators to impose limits on carbon dioxide emissions from electric power plants, particularly coal-fired power plants. Further, far-reaching federal regulations promulgated by the EPA in the last several years, such as MATS, have led to the retirement of coal-fired generating units and a significant reduction in the amount of coal-fired generating capacity in the United States. Please read “Item 1. Business—Environmental, Health and Safety Regulations—*Air Emissions*,” “—*GHG Emissions*” and “—*Hazardous Substances and Wastes*.”

Our industries are subject to extensive and costly laws and regulations, and such current and future laws and regulations, and uncertainties around the same, could increase current operating costs or otherwise negatively impact our operations.

The industries we participate in—coal mining and the third-party operations related to our oil & gas mineral interests—are subject to numerous federal, state, and local laws and regulations. The possibility exists that new laws or regulations may be adopted, or that judicial interpretations or more stringent enforcement of existing laws and regulations may occur, which could materially affect our mining operations, cash flow, and profitability. Furthermore, in June 2024, the U.S. Supreme Court issued decisions affecting judicial review of federal agency-related actions that increase judicial scrutiny of agency authority, shift greater responsibility for statutory interpretation to courts, and expand the timeline in which a plaintiff can sue regulators. In particular, in *Loper Bright Enterprises v. Raimondo*, the U.S. Supreme Court overruled its prior ruling in *Chevron U.S.A., Inc. v. Natural Resources Defense Council, Inc.*, which held that when a statute is ambiguous or silent, courts should not substitute their own judgments regarding the actions of those agencies so long as the federal agencies’ interpretation of the enabling federal statute was reasonable (this was commonly known as “Chevron deference”). In *Loper Bright*, the U.S. Supreme Court held that courts must instead exercise their independent judgment when deciding whether an agency has acted within its statutory authority, and that courts may not defer to an agency interpretation simply because a statute is ambiguous. The overturning of the Chevron doctrine is likely to result in challenges to numerous agency interpretations in various areas of law including energy, environment, taxation, and labor, among others. If these challenges are upheld, they could have both favorable and unfavorable impacts on our business, financial condition, results of operations, and cash flows, depending on whether the interpretations that are overturned were more favorable toward the Partnership’s business and operations than subsequent revised agency interpretations. The likely increase of challenges to agency actions may also increase legal costs, create delays in permitting and project development, and create less certainty around agency actions, at least in the near term.

Our coal mining operations are subject to extensive and costly laws and regulations, and such current and future laws and regulations could increase current operating costs or limit our ability to produce coal.

We are subject to numerous federal, state, and local laws and regulations affecting the coal mining industry, including laws and regulations pertaining to employee health and safety, permitting and licensing requirements, air and water quality standards, plant and wildlife protection, reclamation and restoration of mining properties after mining is completed, the discharge or release of materials into the environment, surface subsidence from underground mining, and the effects that mining has on groundwater quality and availability. Certain of these laws and regulations may impose strict liability without regard to fault or legality of the original conduct. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of remedial liabilities, and the issuance of injunctions limiting or prohibiting the performance of operations. Complying with these laws and regulations could be costly and time-consuming and could delay the commencement or continuation of exploration or production operations. The possibility exists that new laws or regulations may be adopted, or that judicial interpretations or more stringent enforcement of existing laws and regulations may occur, which could materially affect our mining operations, cash flow, and profitability, either through direct impacts on our mining operations, or indirect impacts that discourage or limit our customers’ use of coal. Please read “Item 1. Business—Environmental, Health and Safety Regulations.”

Federal and state laws addressing mine safety practices impose stringent reporting requirements and civil and criminal penalties for violations. Federal and state regulatory agencies continue to interpret and implement these laws and propose new regulations and standards. Implementing and complying with these laws and regulations has increased and will continue to increase our operational expenses and have an adverse effect on our results of operation and financial position. For more information, please read “Item 1. Business—Environmental, Health and Safety Regulations—*Mine Health and Safety Laws.*”

Oil & gas operations are subject to various governmental laws and regulations. Compliance with these laws and regulations can be burdensome and expensive for the operators, and failure to comply could result in the operators incurring significant liabilities, either of which could impact the operators’ willingness to develop our interests.

The operators on the properties in which we hold interests are subject to various federal, state, and local governmental regulations that may change from time to time in response to economic and political conditions. Matters subject to regulation include drilling operations, production and distribution activities, discharges or releases of pollutants or wastes, plugging and abandonment of wells, maintenance and decommissioning of other facilities, the spacing of wells, unitization and pooling of properties, and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil & gas wells below actual production capacity to conserve supplies of oil & gas. In addition, the production, handling, storage, and transportation of oil & gas, as well as the remediation, emission, and disposal of oil & gas wastes, by-products thereof, and other substances and materials produced or used in connection with oil & gas operations are subject to regulation under federal, state, and local laws and regulations primarily relating to the protection of worker health and safety, natural resources, and the environment. Failure to comply with these laws and regulations may result in the assessment of sanctions on the operators, including administrative, civil, or criminal penalties, permit revocations, requirements for additional pollution controls, and injunctions limiting or prohibiting some or all of the operators’ operations on our properties. Moreover, these laws and regulations have generally imposed increasingly strict requirements related to water use and disposal, air pollution control, and waste management. Laws and regulations governing exploration and production may also affect production levels. The operators must comply with federal and state laws and regulations governing conservation matters, including:

- provisions related to the unitization or pooling of the oil & gas properties;
- the establishment of maximum rates of production from wells;
- the spacing of wells;
- the plugging and abandonment of wells; and
- the removal of related production equipment.

Additionally, federal and state regulatory authorities may expand or alter applicable pipeline-safety laws and regulations, compliance with which could require increased capital costs for third-party oil & gas transporters. These transporters may attempt to pass on such costs to the operators, which in turn could affect profitability on the properties in which we own mineral interests.

The operators must also comply with laws and regulations prohibiting fraud and market manipulation in energy markets. To the extent the operators of our properties are shippers on interstate pipelines, they must comply with the tariffs of those pipelines and with federal policies related to the use of interstate capacity. The operators may be required to make significant expenditures to comply with the governmental laws and regulations described above and may be subject to potential fines and penalties if they are found to have violated these laws and regulations. While we cannot predict what actions future federal or state regulators may take with respect to environmental regulation, more expansive and stricter environmental legislation and regulations could be possible in the future. These current laws and regulations and other potential regulations could increase the operating costs of the operators and delay production and could ultimately impact the operators’ ability and willingness to develop our properties.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs, additional operating restrictions or delays, and fewer potential drilling locations, which could adversely affect revenues from our mineral interests.

Oil & gas production on the properties in which we hold mineral interests utilizes hydraulic fracturing. Hydraulic fracturing is a common practice that is used to stimulate the production of hydrocarbons from tight formations, including shales. The process involves the injection of water, sand, and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The SDWA regulates the underground injection of substances through the UIC

program. Hydraulic fracturing is generally exempt from regulation under the UIC program, and the hydraulic-fracturing process is typically regulated by state oil & gas commissions.

Several states where we own interests, including Texas and Oklahoma, have adopted regulations that could restrict or prohibit hydraulic fracturing in certain circumstances or require the disclosure of the composition of hydraulic-fracturing fluids. In addition to state laws, local land-use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general or hydraulic fracturing in particular. We cannot predict what additional state or local requirements may be imposed in the future on oil & gas operations in the states in which we own interests. In the event state, local, or municipal legal restrictions are adopted in areas where the operators conduct operations, the operators could incur substantial costs to comply with these requirements, which could be significant in nature, experience delays, or curtailment in the pursuit of exploration, development, or production activities and perhaps even be precluded from the drilling of wells.

In the past, there was increased public concern regarding hydraulic fracturing around increased risks of induced seismicity, the use of fracturing fluids, impacts on drinking water supplies, use of water, and the potential for impacts to surface water, groundwater, and the environment generally. A number of lawsuits and enforcement actions were initiated across the country implicating hydraulic-fracturing practices. If new laws or regulations are adopted that significantly restrict hydraulic fracturing, those laws could make it more difficult or costly for the operators to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing is further regulated at the federal or state level, fracturing activities on our properties could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements, and also to attendant permitting delays and potential increases in costs. Legislative changes could cause operators to incur substantial compliance costs and adversely affect revenues from our mineral interests. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal or state legislation governing hydraulic fracturing.

Legislation or regulatory initiatives intended to address seismic activity could restrict the operators' drilling and production activities, as well as their ability to dispose of produced water gathered from such activities, which could have a material adverse effect on our business.

State and federal regulatory agencies have recently focused on a possible connection between the hydraulic-fracturing related activities, particularly the underground injection of wastewater into disposal wells, and the increased occurrence of seismic activity, and regulatory agencies at all levels are continuing to study the possible linkage between oil & gas activity and induced seismicity.

In addition, a number of lawsuits have been filed in other states, including in Oklahoma and Texas, alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states have adopted or are considering adopting additional requirements, including requirements in the permitting of produced water disposal wells or otherwise to assess the relationship between seismicity and the use of such wells. For example, both Texas and Oklahoma have imposed certain limits on the permitting or operation of disposal wells in areas with increased instances of induced seismic events. For example, the Oklahoma Corporation Commission ("OCC") has released guidance to operators in the SCOOP and STACK areas for management of certain seismic activity that may be related to hydraulic fracturing activities, and has at times ordered well closures in response to seismic activities. In addition, the TRRC ordered the indefinite suspension of all deep oil & gas-produced water injection wells in the area, effective December 31, 2021. Relatedly, in December 2023, in response to continued seismicity within the area, the TRRC issued a notice to suspend the permits of all deep disposal wells within the Northern Culberson-Reeves Seismic Response Area and, in May 2024, the TRRC released a seismicity response plan curtailing permitted injection volumes for certain wells in the Stanton Seismic Response Area. Most recently, in May 2025, the TRRC released updated guidance for disposal well permits in the Permian Basin that placed new limits on maximum injection pressure and volumes to ensure safety.

The adoption or implementation of any new laws or regulations that restrict the operators' ability to use hydraulic fracturing or dispose of produced water gathered from drilling and production activities by limiting volumes, disposal rates, disposal well locations, or otherwise, or requiring the operators to shut down or limit the operation of disposal wells, could have a material adverse effect on our business, financial condition and results of operations.

Our coal operations, and the third-party operations related to our oil and gas mineral interests, are subject to a series of risks resulting from climate change.

Combustion of fossil fuels, such as the coal we produce and the oil & gas produced from our mineral interests, results in the emission of carbon dioxide into the atmosphere. Additionally, our coal mines may release methane to the atmosphere during operations. Concerns about the environmental impacts of such emissions have resulted in a series of regulatory, political, litigation, and financial risks for our business. Global climate issues continue to attract public and scientific attention. Many scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere could produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods, and other climatic events.

Although Congress has not passed comprehensive climate legislation, almost half of the states have begun to address GHG emissions, primarily through the planned development of emissions inventories, regional GHG cap and trade programs, or the establishment of renewable energy requirements for utilities. Depending on the particular program, we, our customers, or operators of our mineral interests could be required to control GHG emissions or to purchase and surrender allowances for GHG emissions resulting from our operations. Litigation risks are also increasing. For more information, see our risk factor titled "We, our customers, or the operators of our oil & gas mineral interests could be subject to litigation related to climate change."

There are also increasing financial risks for fossil-fuel producers as stakeholders of fossil-fuel energy companies may elect in the future to shift some or all of their support into non-energy related sectors. Institutional lenders who provide financing to fossil-fuel energy companies have in the past become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil-fuel energy companies, although this trend has waned recently and several high-profile banks and institutional investors have withdrawn from various associations that aim to limit financing of industries that emit significant GHG emissions. There is also a risk that financial institutions will be required to adopt policies that have the effect of reducing the funding provided to the fossil-fuel sector. Although we cannot predict the effects of these actions, such limitation of investments in and financing, bonding, and insurance coverages for fossil-fuel energy companies could adversely affect our coal mining or oil & gas production activities.

In addition, some states (such as California) have adopted or are considering adopting laws requiring the disclosure of certain climate-related risks and GHG emission reduction claims. Lawsuits have been filed challenging the implementation of these laws, but we cannot predict the outcome of these suits at this time. Other states are considering similar laws. Non-compliance with these new laws may result in the imposition of substantial fines or penalties. Any new laws or regulations imposing more stringent requirements on our business related to the disclosure of climate related risks may result in reputation harms among certain stakeholders if they disagree with our approach to mitigating climate-related risks, increased compliance costs resulting from the development of any disclosures, and increased costs of and restrictions on access to capital to the extent we do not meet any climate-related expectations or requirements of financial institutions.

We could become subject to new or more stringent international, federal, or state legislation, regulations, or other regulatory initiatives that impose more stringent standards for GHG emissions from fossil-fuel companies and related disclosure obligations whether as a result of newly adopted legislation or regulations or as a result of expanding our businesses and operations into areas already subject to more stringent standards, resulting in increased costs of compliance or costs of consuming, and thereby reducing demand for coal and oil & gas and the profitability of our interests. Additionally, political, litigation, and financial risks could result in either us or oil & gas operators restricting or canceling mining or oil & gas production activities, incurring liability for infrastructure damages due to climate change, or having an impaired ability to continue to operate economically. One or more of these developments, as well as concerted conservation and efficiency efforts that result in reduced electricity consumption, and consumer and corporate preferences for non-fossil-fuel sources, including alternative energy sources, could cause prices and sales of our coal and/or oil & gas to materially decline and could cause our costs to increase and adversely affect our revenues and results of operations.

Climate change may also result in various physical risks, such as the increased frequency or intensity of extreme weather events or changes in meteorological and hydrological patterns that could adversely impact our operations, as well as those of the operators and their supply chain. Such physical risks may result in damage to our facilities or the operators' facilities or otherwise adversely impact operations which could decrease production attributable to our mineral interests. We may not have insurance to cover these risks and the consequences for our or their operations could have a negative impact on the costs and revenues from operations.

Some of our operating subsidiaries lease a portion of the surface properties upon which their mining facilities are located.

Our operating subsidiaries do not, in all instances, own all of the surface properties upon which their mining facilities have been constructed. Certain of the operating companies have constructed and now operate all or some portion of their facilities on properties owned by third parties with whom our subsidiary has entered into a long-term lease. We have no reason to believe that there exists any risk of loss of these leasehold rights given the terms and provisions of the subject leases and the nature and identity of the third-party lessors; however, in the unlikely event of any loss of these leasehold rights, operations could be disrupted or otherwise adversely impacted as a result of increased costs associated with retaining the necessary land use.

Federal and state laws require bonds to secure our obligations related to statutory reclamation requirements and workers' compensation and black lung benefits. Our inability to acquire or failure to maintain surety bonds that are required by federal and state law would have a material adverse effect on us.

Federal and state laws require us to maintain bonds to secure our obligations to repair and return property to its approximate original state after it has been mined (often referred to as "reclaim" or "reclamation"), to pay federal and state workers' compensation and pneumoconiosis (or black lung) benefits, and to satisfy other miscellaneous obligations. These bonds provide assurance that we will perform our statutorily required obligations and are referred to as "surety" bonds. These bonds are typically renewable on a yearly basis. At December 31, 2025, our total of such bonds was \$237.8 million. The amount of surety bonding we are required to maintain may be increased by the governmental agencies holding the bond.

We could have difficulty acquiring or maintaining surety bonds for a variety of reasons, including:

- substantial increases in the amount of bonding required;
- lack of availability, higher expense, or unreasonable terms of new surety bonds, including as a result of external pressures related to fossil-fuel companies;
- the ability of current and future surety bond issuers to increase required collateral, or limitations on the availability of collateral for surety bond issuers due to the terms of our credit agreements; and
- the exercise by third-party surety bondholders of their rights to refuse to renew the surety.

Failure to acquire or maintain the required bonds could subject us to fines and penalties, result in the loss of our mining permits, or imperil our ability to self-insure workers compensation and pneumoconiosis obligations, and could have a material adverse effect on us.

We depend on unaffiliated operators for all of the exploration, development, and production of the oil & gas properties in which we own mineral interests.

Because we depend on unaffiliated third-party operators for all of the exploration, development, and production of our oil & gas properties, we have little to no control over the operations related to our oil & gas properties. The operators of our properties are often not obligated to undertake any development activities. In the absence of a specific contractual obligation, any development and production activities will be subject to their sole discretion (subject, however, to certain implied obligations to develop imposed by state law). The success and timing of drilling and development activities on our oil & gas properties, and whether the operators elect to drill any additional wells on our acreage, depends on several factors that are largely outside of our control, including:

- the capital costs required for drilling activities by the operators of our oil & gas properties, which could be significantly more than anticipated;
- the ability of the operators of our properties to access capital;
- prevailing commodity prices;
- the availability of suitable drilling equipment, production and transportation infrastructure, and qualified operating personnel;
- the operators' expertise, operating efficiency, and financial resources;
- approval of other participants in drilling wells;
- the operators' expected return on investment in wells drilled on our acreage as compared to opportunities in other areas;

- the selection of technology;
- the selection of counterparties for the marketing and sale of production; and
- the rate of production of the reserves.

The operators may elect not to undertake development activities or may undertake these activities in an unanticipated fashion, which could result in significant fluctuations in our oil & gas revenues.

We have little to no control over the timing of future drilling with respect to our oil & gas mineral interests.

All of our oil & gas mineral interests may not ultimately be developed or produced by the operators of our properties. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations, and the decision to pursue the development of an undeveloped drilling location will be made by the operator and not by us. We generally do not have access to the estimated costs of development of these reserves or the scheduled development plans of the operators. Our estimate of reserves assumes that substantial capital expenditures are required to develop the reserves. We cannot be certain that the estimated costs of the development of these reserves are accurate, that development will occur as scheduled or that the results of the development will be as estimated. Delays in the development of our reserves, increases in costs to drill and develop our reserves, or decreases in commodity prices will reduce the future net revenues of our estimated undeveloped reserves and could result in some projects becoming uneconomical. In addition, delays in the development of reserves could force us to reclassify certain of our proved undeveloped reserves as unproved reserves.

We could experience delays in the payment of royalties and be unable to replace operators that do not make required royalty payments, and we may not be able to terminate our leases with defaulting lessees if any of the operators on those leases declare bankruptcy.

A failure on the part of the operators of our properties to make royalty payments gives us the right to terminate the lease and enforce payment obligations under the lease. If we terminate any of our leases, we would seek a replacement operator. However, we might not be able to find a replacement operator and, if we did, we might not be able to enter into a new lease on favorable terms within a reasonable period of time. In addition, the outgoing operator could be subject to a proceeding under the Bankruptcy Code, in which case our right to enforce or terminate the lease for any defaults, including non-payment, could be substantially delayed or otherwise impaired. In general, in a proceeding under the Bankruptcy Code, the bankrupt operator would have substantial time to decide whether to ultimately reject or assume the lease, which could prevent the execution of a new lease or the assignment of the existing lease to another operator. In the event that the operator rejected the lease, our ability to collect amounts owed would be substantially delayed, and our ultimate recovery could be only a fraction of the amount owed or nothing. In addition, if we are able to enter into a new lease with a new operator, the replacement operator may not achieve the same levels of production or sell oil or natural gas at the same price as the operator it replaced.

If the operators of our oil & gas properties suspend our right to receive royalty payments due to title or other issues, our business, financial condition, and/or results of operations could be adversely affected.

Upon a change in ownership of mineral interests, and at regular intervals pursuant to routine audit procedures at each of the operators otherwise at its discretion, the operator of the underlying property has the right to investigate and verify the title and ownership of mineral interests with respect to the properties it operates. If any title or ownership issues are not resolved to its reasonable satisfaction in accordance with customary industry standards, the operator may suspend payment of the related royalty. If an operator of our properties is not satisfied with the documentation we provide to validate our ownership, it may place our royalty payment in suspense until such issues are resolved, at which time we would receive in full payments that would have been made during the suspense period, without interest. Certain of the Operators impose significant documentation requirements for title transfer and may keep royalty payments in suspense for significant periods of time. During the time that an operator puts our assets in pay suspense, we would not receive the applicable mineral or royalty payment owed to us from sales of the underlying oil or natural gas related to such mineral or royalty interest. If a significant amount of our royalty interests is placed in suspense, our results of operations could be reduced significantly.

Our estimated oil & gas reserves are based on many assumptions that could turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

Oil & gas reserve engineering is not an exact science and requires subjective estimates of underground accumulations of oil & gas and assumptions concerning future oil & gas prices, production levels, ultimate recoveries, and operating costs. As a result, the estimated quantities of proved reserves and projections of future production rates could be incorrect. Our estimates of proved reserves and related valuations as of December 31, 2025, were audited by CGA, which conducted a detailed review of all of our properties at that time using the information provided by us. Over time, we may make material changes to reserve estimates taking into account the results of actual drilling, testing, and production. In addition, certain assumptions regarding future oil & gas prices, production levels, and operating costs could prove incorrect. A meaningful portion of our reserve estimates is made without the benefit of lengthy production history, which is less reliable than estimates based on lengthy production history. Any significant variance from these assumptions to actual figures could greatly affect our estimates of reserves and future cash generated from operations. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of oil & gas that are ultimately recovered being different from our reserve estimates.

Furthermore, the present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated reserves. In accordance with rules established by the SEC and the FASB, we base the estimated discounted future net cash flows from our proved reserves on the twelve-month average oil & gas index prices, calculated as the unweighted arithmetic average for the first day-of-the-month price for each month, and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs could differ materially from those used in the present value estimate, and future net present value estimates using then-current prices and costs could be significantly less than the current estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil & gas industry in general. Please see “Item 2. Properties—Oil & Gas Reserves” for more information on our reserves.

Drilling for and producing oil & gas are high-risk activities with many uncertainties that could materially adversely affect our business, financial condition, and results of operations.

The drilling activities of the operators of our properties will be subject to many risks. For example, we will not be able to assure our unitholders that wells drilled by the operators of our properties will be productive. Drilling for oil & gas often involves unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient oil or gas to return a profit at then realized prices after deducting drilling, operating, and other costs. The seismic data and other technologies used do not provide conclusive knowledge prior to drilling a well that oil or gas is present or that it can be produced economically. The costs of exploration, exploitation, and development activities are subject to numerous uncertainties beyond our control and increases in those costs can adversely affect the economics of a project. Further, the operators’ drilling and producing operations could be curtailed, delayed, canceled, or otherwise negatively impacted as a result of other factors, including:

- unusual or unexpected geological formations or earthquakes;
- loss of drilling fluid circulation;
- title problems;
- facility or equipment malfunctions;
- unexpected operational events;
- shortages or delivery delays of equipment and services;
- compliance with environmental and other governmental requirements; and
- adverse weather conditions.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources, and equipment, pollution, environmental contamination or loss of wells, and other regulatory penalties. In the event that planned operations, including the drilling of development wells, are delayed or canceled, or existing wells or development wells have lower than anticipated production due to one or more of the factors above or for any other reason, our financial condition, results of operations, and free cash flow could be materially adversely affected.

The marketability of oil & gas production is dependent upon transportation and other facilities, certain of which neither we nor the operators of our properties control. If these facilities are unavailable, the operators' operations could be interrupted and our results of operations and cash available for distribution could be materially adversely affected.

The marketability of the operators' oil & gas production will depend in part upon the availability, proximity, and capacity of transportation facilities, including gathering systems, trucks, and pipelines, owned by third parties. Neither we nor, in general, the operators of our properties control these third-party transportation facilities and the operators' access to them may be limited or denied. Insufficient production from the wells on our acreage or a significant disruption in the availability of third-party transportation facilities or other production facilities could adversely impact the operators' ability to deliver to market or produce oil & gas and thereby cause a significant interruption in the operators' operations. If they are unable, for any sustained period, to implement acceptable delivery or transportation arrangements or encounter production-related difficulties, they may be required to shut-in or curtail production. In addition, the amount of oil & gas that can be produced and sold may be subject to curtailment in certain other circumstances outside of our or the operators' control, such as pipeline interruptions due to maintenance, excessive pressure, the inability of downstream processing facilities to accept unprocessed gas, physical damage to the gathering system or transportation system or lack of contracted capacity on such systems. The curtailments arising from these and similar circumstances could last from a few days to several months. In many cases, we and the operators are provided with limited notice, if any, as to when these curtailments will arise and the duration of such curtailments. Any such shut-in or curtailment, or an inability to obtain favorable terms for delivery of the oil & gas produced from our acreage, could adversely affect our financial condition, results of operations, and cash available for distribution.

We do not currently enter into hedging arrangements with respect to commodity production from our properties, and we will be exposed to the impact of decreases in the price of such commodities.

We have not entered into hedging arrangements to establish, in advance, a price for the sale of the oil & gas or the coal produced from our properties, and we may not enter into such arrangements in the future. As a result, although we could realize the benefit of any short-term increase in commodity prices, we will not be protected against commodity price decreases or prolonged periods of low commodity prices, which could materially adversely affect our business, results of operations and cash available for distribution.

In the future, we may enter into hedging transactions with the intent of reducing volatility in our cash flows due to fluctuations in the price of oil & gas or coal. However, these hedging activities may not be as effective as we intend in reducing the volatility of our cash flows and, if entered into, are subject to the risks that the terms of the derivative instruments will be imperfect, a counterparty may not perform its obligations under a derivative contract, there could be a change in the expected differential between the underlying commodity price in the derivative instrument and the actual price received, our hedging policies and procedures may not be properly followed and the steps we take to monitor our derivative financial instruments may not detect and prevent violations of our risk management policies and procedures, particularly if deception or other intentional misconduct is involved. Further, we could be limited in receiving the full benefit of increases in commodity prices as a result of these hedging transactions. The occurrence of any of these risks could prevent us from realizing the benefit of a derivative contract.

Expansions and acquisitions involve a number of risks, any of which could cause us not to realize the anticipated benefits.

Since our formation and the acquisition of our predecessor in August 1999, we have expanded our coal operations by adding and developing mines in existing, adjacent, and neighboring properties. Similarly, the profitability of our business depends significantly upon acquisitions to grow our coal and oil & gas reserves, production, and free cash flow. Our future growth could be limited if we are unable to continue to make acquisitions in either our coal operations or our royalties segments, or if we are unable to successfully integrate the companies, businesses, or properties we acquire. We may not be successful in consummating any acquisitions and the consequences of undertaking these acquisitions are unknown.

Competition for acquisitions of coal and oil & gas mineral interests could increase the cost of, or cause us to refrain from, completing acquisitions. Our ability to complete acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing under acceptable terms. In addition, these acquisitions could be in geographic regions in which we do not currently hold properties, which could subject us to additional and unfamiliar legal and regulatory

requirements. No assurance can be given that we will be able to identify suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms, or successfully acquire identified targets.

The process of integrating acquired assets could involve unforeseen difficulties and could require a disproportionate amount of our managerial and financial resources. If we are unable to successfully integrate the companies, businesses, or properties we acquire, our profitability could decline and we could experience a material adverse effect on our business, financial condition, or results of operations. Expansion and acquisition transactions involve various inherent risks, including:

- uncertainties in assessing the value, strengths, and potential profitability of expansion and acquisition opportunities;
- uncertainties in identifying the extent of all weaknesses, risks, contingent and other liabilities of, expansion and acquisition opportunities;
- the ability to achieve identified operating and financial synergies anticipated to result from an expansion or an acquisition;
- problems that could arise from the integration of the new operations; and
- unanticipated changes in business, industry, or general economic conditions that affect the assumptions underlying our rationale for pursuing the expansion or acquisition opportunity.

Any one or more of these factors could cause us not to realize the benefits anticipated to result from an expansion or acquisition. Any expansion or acquisition opportunities we pursue could materially affect our liquidity and capital resources and could require us to incur indebtedness, seek equity capital, or both. Future expansions or acquisitions could result in us assuming more long-term liabilities relative to the value of the acquired assets than we have assumed in our previous expansions and/or acquisitions.

The integration of any expansions or acquisitions that we complete will be subject to substantial risks.

Even if we make expansions or acquisitions that we believe will increase our coal or mineral revenue, any expansion or acquisition involves potential risks, including, among other things:

- the validity of our assumptions about estimated proved reserves, future production, prices, revenues, capital expenditures, the operating expenses, and costs the operators would incur to develop the minerals;
- a decrease in our liquidity by using a significant portion of our cash generated from operations or borrowing capacity to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur debt to finance acquisitions;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which any indemnity we receive is inadequate or uncollectable;
- mistaken assumptions about the overall cost of equity or debt;
- our ability to obtain satisfactory title to the assets we acquire;
- an inability to hire, train or retain qualified personnel to manage and operate our growing mineral assets; and
- the occurrence of other significant changes, such as impairment of properties, goodwill or other intangible assets, asset devaluation, or restructuring charges.

We may not be able to effectively identify investment opportunities in the growth and development of energy and related infrastructure on favorable terms, or at all, and failure to do so may limit our future growth.

Part of our strategy includes positioning ourselves as a reliable energy provider for the future by pursuing strategic investments that leverage our core competencies and relationships with electric utilities, industrial customers, and federal and state governments. This strategy depends on our ability to successfully identify and evaluate investment opportunities. The number of opportunities may be limited, and we will compete with other investors for these limited opportunities, which could make them more expensive and the returns for our investments less attractive and possibly cause us to refrain from making them at all. Further, certain opportunities will depend on technological and other advancements that may not be within our control and may not come to fruition or be economically feasible in the near term, and we may fail to realize, and in some cases have failed to realize, the anticipated benefit of our investments. Any new opportunities also may depend on the viability of new assets or businesses that are contingent on public policy mechanisms including investment tax credits, subsidies, renewable portfolio standards and carbon trading plans. These mechanisms have been implemented at the state and federal levels to support the development of renewable energy, demand-side, and other infrastructure

technologies. The availability and continuation of public policy support mechanisms will drive a significant part of the economics and viability of investments generally, as well as our participation in them.

Our inability to obtain commercial insurance at acceptable rates or our failure to adequately reserve for self-insured exposures could increase our expenses and have a negative impact on our business.

We believe that commercial insurance coverage is prudent in certain areas of our business for risk management. Insurance costs could increase substantially in the future and could be affected by natural disasters, fear of terrorism, financial irregularities, cybersecurity breaches and other fraud at publicly traded companies, intervention by the government, an increase in the number of claims received by the carriers, and a decrease in the number of insurance carriers. In addition, the carriers with which we hold our policies could go out of business or be otherwise unable to fulfill their contractual obligations or could disagree with our interpretation of the coverage or the amounts owed. In addition, for certain types or levels of risk, such as risks associated with certain natural disasters or terrorist attacks, we may determine that we cannot obtain commercial insurance at acceptable rates, if at all. Therefore, we may choose to forego or limit our purchase of relevant commercial insurance, choosing instead to self-insure one or more types or levels of risks. If we suffer a substantial loss that is not covered by commercial insurance or our self-insurance reserves, the loss and related expenses could harm our business and operating results. Also, exposures exist for which no insurance may be available and for which we have not reserved. In addition, environmental activists could try to hamper fossil-fuel companies by other means including pressuring insurance and surety companies into restricting access to certain needed coverages.

Tax Risks to Our Common Unitholders

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes, and our not being subject to a material amount of entity-level taxation. If the IRS were to treat us as a corporation for U.S. federal income tax purposes, or we become subject to entity-level taxation for state tax purposes, our cash available for distribution to you would be substantially reduced.

The anticipated after-tax benefit of an investment in our common units depends largely on our being treated as a partnership for U.S. federal income tax purposes.

Even though we are organized as a limited partnership under Delaware law, we would be treated as a corporation for U.S. federal income tax purposes unless we satisfy a “qualifying income” requirement. Based on our current operations and current Treasury Regulations, we believe we satisfy the qualifying income requirement. However, we have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay U.S. federal income tax on our taxable income at the corporate tax rate, and would likely be liable for state income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions, or credits would flow through to our unitholders. Because taxes would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Therefore, our treatment as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, or other forms of taxation. If any state were to impose a tax upon us as an entity, the cash available for distribution to you would be reduced and the value of our units could be negatively impacted.

The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes or differing interpretations, possibly applied on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. Members of Congress have frequently proposed and considered substantive changes to the existing U.S. federal income tax laws that would affect publicly traded partnerships, including proposals that would eliminate our ability to qualify for

partnership tax treatment. Recent proposals have provided for the expansion of the qualifying income exception for publicly traded partnerships in certain circumstances and other proposals have provided for the total elimination of the qualifying income exception upon which we rely for our partnership tax treatment.

In addition, the Treasury Department has issued, and in the future may issue, regulations interpreting those laws that affect publicly traded partnerships. There can be no assurance that there will not be further changes to U.S. federal income tax laws or the Treasury Department's interpretation of the qualifying income rules in a manner that could impact our ability to qualify as a partnership in the future.

Any modification to the U.S. federal income tax laws and the interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any changes or other proposals will ultimately be enacted. Any similar or future legislative changes could negatively impact the value of an investment in our common units. You are urged to consult with your own tax advisor with respect to the status of regulatory or administrative developments and proposals and their potential effect on your investment in our common units.

If the IRS were to contest the U.S. federal income tax positions we take, it may adversely impact the market for our common units, and the costs of any such contest would reduce cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes. The IRS may adopt positions that differ from the positions that we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. Moreover, the costs of any contest between us and the IRS will result in a reduction in our cash available for distribution to our unitholders and thus will be borne indirectly by our unitholders.

If the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustments directly from us, in which case our cash available for distribution to our unitholders could be reduced and our current and former unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders' behalf.

If the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustments directly from us. To the extent possible, our general partner may elect to either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, issue a revised information statement to each unitholder and former unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our unitholders and former unitholders take such audit adjustment into account and pay any resulting taxes (including applicable penalties and interest) in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. As a result, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to pay taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced and our current and former unitholders may be required to indemnify us for any taxes (including any applicable penalties and interest) resulting from such audit adjustments that were paid on such unitholders' behalf.

Our unitholders are required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Our unitholders are required to pay any U.S. federal income taxes and, in some cases, state and local income taxes, on their share of our taxable income whether or not they receive cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

Tax gain or loss on the disposition of our common units could be more or less than expected.

If a unitholder sells units, the unitholder will recognize a gain or loss equal to the difference between the amount realized and that unitholder's tax basis in those common units. Because distributions in excess of a unitholder's allocable share of our net taxable income decrease such unitholder's tax basis in its units, the amount, if any, of such prior excess distributions with respect to the units a unitholder sells will, in effect, become taxable income to a unitholder if it sells such units at a price greater than its tax basis in those units, even if the price such unitholder receives is less than its original cost. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if a unitholder sells its units, a unitholder may incur a tax liability in excess of the amount of cash received from the sale.

A substantial portion of the amount realized from a unitholder's sale of our units, whether or not representing gain, may be taxed as ordinary income to such unitholder due to potential recapture items, including depreciation recapture. Thus, a unitholder may recognize both ordinary income and capital loss from the sale of units if the amount realized on a sale of such units is less than such unitholder's adjusted basis in the units. Net capital loss may only offset capital gains and, in the case of individuals, up to \$3,000 of ordinary income per year. In the taxable period in which a unitholder sells its units, such unitholder may recognize ordinary income from our allocations of income and gain to such unitholder prior to the sale and from recapture items that generally cannot be offset by any capital loss recognized upon the sale of units.

Unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

In general, we are entitled to a deduction for interest paid or accrued on indebtedness properly allocable to our trade or business during our taxable year. However, our deduction for "business interest" is limited to the sum of our business interest income and 30% of our "adjusted taxable income." For the purposes of this limitation, our adjusted taxable income is computed without regard to any business interest expense or business interest income. If our "business interest" is subject to limitation under these rules, our unitholders will be limited in their ability to deduct their share of any interest expense that has been allocated to them. As a result, unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

Tax-exempt entities face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investment in our common units by tax-exempt entities, such as employee benefit plans and IRAs, raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from U.S. federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Additionally, all or part of any gain recognized by such tax-exempt organization upon a sale or other disposition of our units may be unrelated business taxable income and may be taxable to them. Tax-exempt entities should consult a tax advisor before investing in our common units.

Non-U.S. unitholders will be subject to U.S. taxes and withholding with respect to their income and gain from owning our units.

Non-U.S. unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a U.S. trade or business. Income allocated to our unitholders and any gain from the sale of our units will generally be considered to be "effectively connected" with a U.S. trade or business. As a result, distributions to a non-U.S. unitholder will be subject to withholding at the highest applicable effective tax rate and a non-U.S. unitholder who sells or otherwise disposes of a unit will also be subject to U.S. federal income tax on the gain realized from the sale or disposition of that unit. In addition to the withholding tax imposed on distributions of effectively connected income, distributions to a non-U.S. unitholder will also be subject to a 10% withholding tax on the amount of any distribution in excess of our cumulative net income. As we do not compute our cumulative net income for such purposes due to the complexity of the calculation and lack of clarity in how it would apply to us, we intend to treat all of our distributions as being in excess of our cumulative net income for such purposes and subject to such 10% withholding tax. Accordingly, distributions to a non-U.S. unitholder will be subject to a combined withholding tax rate equal to the sum of the highest applicable effective tax rate and 10%.

Moreover, the transferee of an interest in a partnership that is engaged in a U.S. trade or business is generally required to withhold 10% of the “amount realized” by the transferor unless the transferor certifies that it is not a foreign person. While the determination of a partner’s “amount realized” generally includes any decrease of a partner’s share of the partnership’s liabilities, the Treasury regulations provide that the “amount realized” on a transfer of an interest in a publicly traded partnership, such as our common units, will generally be the amount of gross proceeds paid to the broker effecting the applicable transfer on behalf of the transferor, and thus will be determined without regard to any decrease in that partner’s share of a publicly traded partnership’s liabilities. For a transfer of interests in a publicly traded partnership that is effected through a broker, the obligation to withhold is imposed on the transferor’s broker. Current and prospective non-U.S. unitholders should consult their tax advisors regarding the impact of these rules on an investment in our common units.

We treat each purchaser of our common units as having the same tax benefits without regard to the common units actually purchased. The IRS may challenge this treatment, which could adversely affect the value of our common units.

Because we cannot match transferors and transferees of common units, we have adopted certain methods for allocating depreciation and amortization deductions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to the use of these methods could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from any sale of common units and could have a negative impact on the value of our units or result in audit adjustments to a unitholder’s tax returns.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based on the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based on the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. Similarly, we generally allocate (i) certain deductions for depreciation of capital additions, (ii) gain or loss realized on a sale or other disposition of our assets, and (iii) in the discretion of the general partner, any other extraordinary item of income, gain, loss or deduction based on ownership on the Allocation Date. Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of our proration method. If the IRS were to challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are the subject of a securities loan (e.g., a loan to a “short seller” to cover a short sale of units) may be considered as having disposed of those units. If so, such unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because there are no specific rules governing the U.S. federal income tax consequence of loaning a partnership interest, a unitholder whose units are the subject of a securities loan may be considered as having disposed of the loaned units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a securities loan are urged to consult a tax advisor to determine whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

Certain U.S. federal income tax deductions currently available with respect to coal mining and production may be eliminated as a result of future legislation.

In past years, members of the U.S. Congress have indicated a desire to eliminate certain key U.S. federal income tax provisions currently applicable to coal companies, including the percentage depletion allowance with respect to coal properties. Elimination of those provisions would have no impact on our financial statements or results of operations. However, elimination of such provisions could result in unfavorable tax consequences for our unitholders and, as a result, could negatively impact our unit price.

Our unitholders will likely be subject to state and local taxes and income tax return filing requirements in jurisdictions where they do not live as a result of investing in our common units.

In addition to U.S. federal income taxes, our unitholders may be subject to other taxes, such as state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements.

We currently own assets and conduct business in multiple states that currently impose a personal income tax on individuals, corporations and other entities. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose a personal income tax. It is our unitholders' responsibility to file all U.S. federal, foreign, state, and local tax returns and pay any taxes due in these jurisdictions. Unitholders should consult with their own tax advisors regarding the filing of such tax returns, the payment of such taxes, and the deductibility of any taxes paid.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

Description of Processes for Assessing, Identifying, and Managing Cybersecurity Risks

We operate in an increasingly interconnected digital landscape and we recognize the importance of assessing, identifying, and managing material risks from cybersecurity threats. In the normal course of business, we may collect and store certain sensitive information, including proprietary and confidential business information, intellectual property, sensitive third-party information, employee information and other personal information. We rely on our own information systems and third-party information systems for the management of this information in addition to our management of business processes including inventory, payment of obligations, collection of cash, human capital management, financial tools and other processes and procedures. Our ability to manage our business effectively depends on the reliability, security and capacity of these systems. We seek to address these risks by safeguarding assets, data, and operations through the cybersecurity risk management processes described below:

Risk Assessment:

Regular assessments are conducted across our systems, networks, and data infrastructure to identify potential cybersecurity threats and vulnerabilities. These assessments include penetration testing, vulnerability scanning, and red teaming exercises conducted by third-party service providers, which help us to evaluate the likelihood and potential impact of cybersecurity incidents. Feedback from these assessments is incorporated into our systems and procedures through upgrades intended to further improve our security posture.

Incident Identification and Response:

A monitoring and detection system has been implemented to help identify cybersecurity incidents. The IT Security Department is tasked with monitoring certain network activities, logs, and system behavior, leveraging threat detection technologies. In the event of any breach or cybersecurity incident, we have an incident response plan that is designed to follow industry best practices and aligns with legal and regulatory requirements. This plan is designed to provide for immediate action to contain the incident, mitigate the impact, and restore normal operations efficiently.

Cybersecurity Training and Awareness:

Cybersecurity awareness among our employees is promoted with regular training and awareness programs. Employees receive training on recognizing and reporting potential cybersecurity threats, best practices for data protection, and adhering to cybersecurity policies and procedures. Additionally, periodic simulated phishing exercises are conducted to enhance employee readiness in identifying and mitigating phishing attacks.

Access Controls:

Access control policies have been implemented to limit unauthorized access to sensitive information and we seek to maintain and monitor critical systems. Multi-factor authentication is used for remote access, use of privileged accounts and access to critical systems.

Encryption and Data Protection:

Encryption methods are used to protect sensitive data in transit and at rest. This includes the encryption of customer data, financial information, and other confidential data.

The above cybersecurity risk management processes are integrated into the Partnership's overall risk management program. Cybersecurity threats are understood to be dynamic and intersect with various other enterprise risks. As such, cybersecurity is considered an important component of our enterprise-wide risk management approach. We have assembled a Cybersecurity Steering Committee comprised of IT management, cybersecurity specialists, and representatives of business management, including the CTO and internal legal counsel. The Cybersecurity Steering Committee reviews information security policies and cybersecurity risks in conjunction with other operational, financial, and strategic risks to ensure alignment with our business objectives. The Cybersecurity Steering Committee convenes

regularly to review and monitor the Partnership's programs for the prevention, detection, mitigation, and remediation of cybersecurity incidents. The Cybersecurity Steering Committee receives reports on security incidents, threat intelligence, and vulnerability assessments from our IT Security Department.

The Cybersecurity Steering Committee regularly reports to the CFO through the CTO and reports annually on cybersecurity to the Audit Committee during a scheduled meeting. These reports include, as appropriate, updates on the current cybersecurity landscape, incident trends, and any significant developments that may impact the Partnership's security posture.

To enhance the effectiveness of our cybersecurity program, we periodically engage external assessors, consultants, and auditors. These third-party service providers conduct independent evaluations of our cybersecurity measures, helping to identify areas for improvement and adherence to industry standards and best practices.

Our IT Security Department recognizes that third-party service providers may introduce cybersecurity risks to our organization. In an effort to mitigate these risks, we have implemented a process designed to assess and oversee the cybersecurity practices of our vendors. Before engaging with any third-party cybersecurity service provider, we conduct due diligence to evaluate their cybersecurity capabilities. Additionally, we include cybersecurity requirements in our contracts with these providers, requiring them to adhere to certain cybersecurity standards and protocols.

Impact of Risks from Cybersecurity Threats

The energy industry increasingly depends on information and operational technology to sustain critical functions. However, the rise in cybersecurity incidents, whether caused by deliberate attacks or accidental events, poses substantial challenges. As these threats grow in complexity and scale, the industry's efforts to prevent, detect, mitigate, and remediate such incidents become progressively more demanding and complex.

During 2025 and through the date of this Annual Report on Form 10-K, though the Partnership and our service providers may have experienced cybersecurity incidents, we are not aware of any cybersecurity threats, including as a result of any previous cybersecurity incidents, that have materially affected or are reasonably likely to materially affect the Partnership, including our business strategy, result of operations, or financial condition. However, we acknowledge that cybersecurity threats are continually evolving, and the possibility of future cybersecurity incidents remains. Our IT Security Department aims to monitor and assess these risks to maintain the security and continuity of our operations. Despite the implementation of our cybersecurity programs, our security measures cannot guarantee that a significant cyberattack will not occur. A successful attack on our IT systems could have significant consequences to our business. While we devote resources to our security measures to protect our systems and information, these measures cannot provide absolute security. Please see "Item 1A. Risk Factors" for additional information about the risks to our business associated with a breach or compromise to our information technology systems.

Board of Directors' Oversight of Risks from Cybersecurity Threats

The Board of Directors oversees risks from cybersecurity threats. Recognizing the importance of cybersecurity to the success and resilience of our business, the Board considers cybersecurity to be an important aspect of corporate governance. To facilitate effective oversight, the Audit Committee and the Board of Directors hold discussions with management, including the CTO on cybersecurity risks, incident trends, and the effectiveness of cybersecurity measures annually and as needed during both scheduled and special meetings. If new material cybersecurity risks arise, the Board of Directors and the Audit Committee are informed through regular discussions between the CFO and both the Chairman of the Board and the Audit Committee Chair. These discussions are then brought to the attention of the Board of Directors and Audit Committee at the next meeting.

Management's Role and Expertise

The CTO and the Cybersecurity Steering Committee are responsible for overseeing and executing our cybersecurity strategy, including the assessment and management of cybersecurity risks. The CTO reports directly to the CFO and maintains communication with the Audit Committee, the Board of Directors and the Cybersecurity Steering Committee with respect to information security and cybersecurity matters.

The CTO holds a Master of Business Administration from the University of Kentucky/University of Louisville's joint executive program and has an extensive background in information security, risk management, and incident response with over twenty years of varying information technology roles with increasing responsibility at both private and public companies. The CTO is supported by a dedicated team of cybersecurity professionals, each bringing diverse expertise in areas such as network security, data protection, and threat intelligence.

ITEM 2. PROPERTIES

COAL MINERAL RESOURCES AND RESERVES

Overview of Coal Properties

Our coal properties are located in the Illinois Basin and the Appalachia Basin. Our Illinois Basin properties are located in western Kentucky, southern Illinois, and southern Indiana. Our Appalachian properties are located in eastern Kentucky, western Maryland, western Pennsylvania, and northern West Virginia. Mining operations on our coal properties consist of underground mines that produce bituminous coal that is sold to customers principally for electric power generation (thermal) and the production of steel (metallurgical). In addition to our coal mining operations, we also hold coal mineral interests that we lease/sublease to our operations or hold for lease/sublease to our operations or others. For a detailed overview of our coal mining operations and our coal royalty activities, please see “Item 1. Business—Coal Mining Operations” and “Item 1. Business—Mineral Interest Activities”, respectively.

Evaluation and Review of Coal Mineral Resources and Reserves

Numerous uncertainties are inherent in estimating coal mineral resources and reserves, and the estimates are subject to change as additional information becomes available or circumstances change. Significant factors and assumptions related to the uncertainty in estimating coal mineral reserves and resources include:

- geological and mining conditions, which may not be fully identified by available exploration data and/or differ from our experiences in areas where we currently mine;
- the percentage of coal in the ground ultimately recoverable;
- historical production from the area compared with production from other producing areas;
- the assumed effects of regulation and taxes by governmental agencies;
- future improvements in mining technology; and
- assumptions concerning future coal prices, operating costs, capital expenditures, severance and excise taxes, and development and reclamation costs.

Each of the factors which impacts reserve and resource estimation may vary considerably from the assumptions used in making the estimation and, as a result, the estimates in this report may not accurately reflect the actual coal reserves and resources. Actual production, revenues, and expenditures with respect to the coal reserves will likely vary from the assumptions used in these estimates, and these variances may be material. Government regulations and other pressures may result in the closure of coal-fired electric generating plants earlier than assumed. Such changes would reduce the economic viability of our mining operations and could have a material adverse impact on our operations and financial results.

Under SEC rules, a mineral resource is a concentration or occurrence of a material of economic interest in or on the Earth’s crust in such form, grade or quality, and quantity that there are reasonable prospects for economic extraction. A mineral resource is a reasonable estimate of mineralization, considering relevant factors such as cut-off grade, likely mining dimensions, location or continuity that, with the assumed and justifiable technical and economic conditions, is likely to, in whole or in part, become economically extractable. A mineral reserve is an estimate of tonnage and grade or quality of indicated and measured mineral resources that, in the opinion of the qualified person, can be the basis of an economically viable project. More specifically, it is the economically mineable part of a measured or indicated mineral resource, which includes diluting materials and allowances for losses that may occur when the material is mined or extracted.

The coal mineral resource and reserve estimates included in this Annual Report on Form 10-K were prepared by an independent, qualified engineering firm, RESPEC. We provided RESPEC with property control, mine plans, production, revenue, costs, capital, and other information considered by RESPEC in making their estimates. As part of our internal controls, our geologists and engineers review the integrity, accuracy, and timeliness of the data provided to RESPEC that they considered in calculating their coal mineral resource and reserve estimates. We also review the geologic data, mining assumptions, and methodology used by RESPEC to estimate our coal mineral resources and reserves. Our geologists and engineers also meet with RESPEC periodically during the year to discuss the assumptions and methods used in the coal mineral resource and reserve estimation process.

RESPEC, an independent third-party engineering firm, does not have an interest in any of our properties and is not employed on a contingent basis. RESPEC prepared the initial TRS for each of our material mining properties. The TRSs will be updated when there are material changes to the coal mineral reserve or resource estimates. The most recent TRSs for our material mining operations are included as exhibits to our Annual Report on Form 10-K.

Summary of Coal Mineral Resources and Reserves

Coal Mineral Resources

Most of our coal properties designated as mineral resources are of thickness, quality, and mineability similar to our mineral reserves, and all are proximal to existing infrastructure such as power, water, transportation, facilities, etc. However, we have not completed pre-feasibility or feasibility studies with respect to our coal properties designated as mineral resources, as is required to convert the mineral resources into mineral reserves. There is no certainty that all or any part of the mineral resources will be converted into mineral reserves.

The following table sets forth our coal mineral resources, exclusive of coal mineral reserves, at December 31, 2025:

Resources (tons in millions)	Heat	Pounds SO2 per MMBtu			Resource Classification				Ownership		
	Content (Btus per pound)	<1.2	1.2-2.5	>2.5	Measured	Indicated	Combined	Inferred	Owned	Leased	Total
(1)											
Illinois Basin											
Dotiki (KY)	12,100	—	2.4	73.6	51.2	24.8	76.0	—	27.5	48.5	76.0
Henderson/Union (KY) (2)	11,400	—	3.0	412.2	128.7	229.5	358.2	57.0	74.7	340.5	415.2
River View (KY) (2)	11,400	—	—	0.4	0.3	—	0.3	0.1	0.1	0.3	0.4
Sebree South (KY)	11,750	—	—	43.0	22.1	16.8	38.9	4.1	0.2	42.8	43.0
Warrior (KY)	12,300	—	—	8.2	6.7	0.9	7.6	0.6	1.2	7.0	8.2
Gibson South (IN)	11,500	—	—	4.0	2.2	1.8	4.0	—	2.3	1.7	4.0
Hamilton County (IL)	11,650	4.9	35.4	389.3	212.3	214.5	426.8	2.8	36.0	393.6	429.6
Region Total		4.9	40.8	930.7	423.5	488.3	911.8	64.6	142.0	834.4	976.4
Appalachian Basin											
Mountain View (WV)	13,200	—	0.4	8.3	4.1	4.3	8.4	0.3	1.8	6.9	8.7
MC Mining (KY)	12,800	1.5	—	—	1.4	0.1	1.5	—	—	1.5	1.5
Tunnel Ridge (WV)	12,600	—	—	0.9	—	—	—	0.9	0.9	—	0.9
Penn Ridge (PA)	12,500	—	—	78.0	21.9	53.3	75.2	2.8	78.0	—	78.0
Region Total		1.5	0.4	87.2	27.4	57.7	85.1	4.0	80.7	8.4	89.1
Total		6.4	41.2	1,017.9	450.9	546.0	996.9	68.6	222.7	842.8	1,065.5
% of Total		0.6%	3.9%	95.5%	42.3%	51.2%	93.6%	6.4%	20.9%	79.1%	100.0%

(1) Combined resources are defined as measured plus indicated resources.

(2) As with our Henderson County mine, River View (KY) has geographic overlap with Henderson/Union (KY) and there is potential for further development of our resources from the existing facilities. See Individual Property Disclosures for more detail.

On December 31, 2025, we had approximately 1.066 billion tons of coal mineral resources. Tonnages are reported on a clean recoverable basis with average long-term pricing based on available third-party forecasts and historical pricing adjusted for quality at the end of 2025 in a range from approximately \$46 to \$59 per short ton in the Illinois Basin and from approximately \$64 to \$117 per short ton in the Appalachian Basin, which are the prices used by RESPEC to verify the amount of coal mineral resources. Coal sales prices vary based on coal quality, access to transportation, and other factors at each location. All resources are classified as underground mineable in the exploration stage.

Coal Mineral Reserves

Reserves at our active operations are currently in production and meet the other requirements to be considered reserves as defined by the SEC. There is no certainty that all our mineral reserves remain economically viable as fluctuations in pricing and costs occur within the coal industry.

The following table sets forth coal mineral reserve information, exclusive of the coal mineral resources, at December 31, 2025:

Reserves (tons in millions)	Heat	Pounds SO2 per MMBtu			Classification		Ownership		Total
	Content (Btus	<1.2	1.2-2.5	>2.5	Proven	Probable	Owned	Leased	
	per pound)								
Illinois Basin Operations									
Warrior (KY)	12,300	—	—	36.4	25.6	10.8	7.9	28.5	36.4
River View (KY)	11,400	—	—	287.9	173.4	114.5	53.3	234.6	287.9
Hamilton County (IL)	11,650	—	—	104.9	48.7	56.2	7.8	97.1	104.9
Gibson South (IN)	11,500	0.1	3.9	28.2	25.1	7.1	7.0	25.2	32.2
Region Total		0.1	3.9	457.4	272.8	188.6	76.0	385.4	461.4
Appalachian Basin Operations									
MC Mining (KY)	12,800	6.1	1.4	—	6.9	0.6	—	7.5	7.5
Mountain View (WV)	13,200	—	5.9	2.6	8.1	0.4	—	8.5	8.5
Tunnel Ridge (WV)	12,600	—	—	109.1	59.9	49.2	12.9	96.2	109.1
Region Total		6.1	7.3	111.7	74.9	50.2	12.9	112.2	125.1
Total		6.2	11.2	569.1	347.7	238.8	88.9	497.6	586.5
% of Total		1.1%	1.9%	97.0%	59.3%	40.7%	15.2%	84.8%	100.0%

On December 31, 2025, we had approximately 586.5 million tons of coal mineral reserves. Tonnages are reported on a clean recoverable basis with average long-term pricing based on available third-party forecasts and historical pricing adjusted for quality at the end of 2025 in a range from approximately \$46 to \$59 per short ton in the Illinois Basin and from approximately \$64 to \$117 per short ton in the Appalachian Basin, which are the prices used by RESPEC to verify the amount of coal mineral reserves. Coal sales prices vary based on coal quality, access to transportation, and other factors at each location. All reserves are classified as underground mineable in the development or production stage.

Mining Operations

The following table sets forth production and other data about our mining operations:

Operations	Location	Tons Produced			Transportation	Equipment
		2025	2024	2023		
(in millions)						
Illinois Basin Operations						
Warrior	Kentucky	4.5	4.4	4.4	CSX, NS, PAL, truck, barge	CM
River View	Kentucky	9.6	9.3	9.9	Truck, barge	CM
Hamilton County	Illinois	6.5	4.8	5.6	CSX, EVW, NS, barge	LW, CM
Gibson South	Indiana	5.5	5.7	5.3	CSX, NS, truck, barge	CM
Region Total		26.1	24.2	25.2		
Appalachian Basin Operations						
MC Mining/Excel	Kentucky	0.7	0.9	1.2	CSX, truck, barge	CM
Mountain View	West Virginia	1.2	1.1	0.8	CSX, truck	LW, CM
Tunnel Ridge	West Virginia	5.2	6.0	7.7	CSX, NS, barge	LW, CM
Region Total		7.1	8.0	9.7		
TOTAL						
		33.2	32.2	34.9		

CSX - CSX Railroad
EVW - Evansville Western Railroad
NS - Norfolk Southern Railroad
PAL - Paducah & Louisville Railroad
CM - Continuous Miner
LW - Longwall

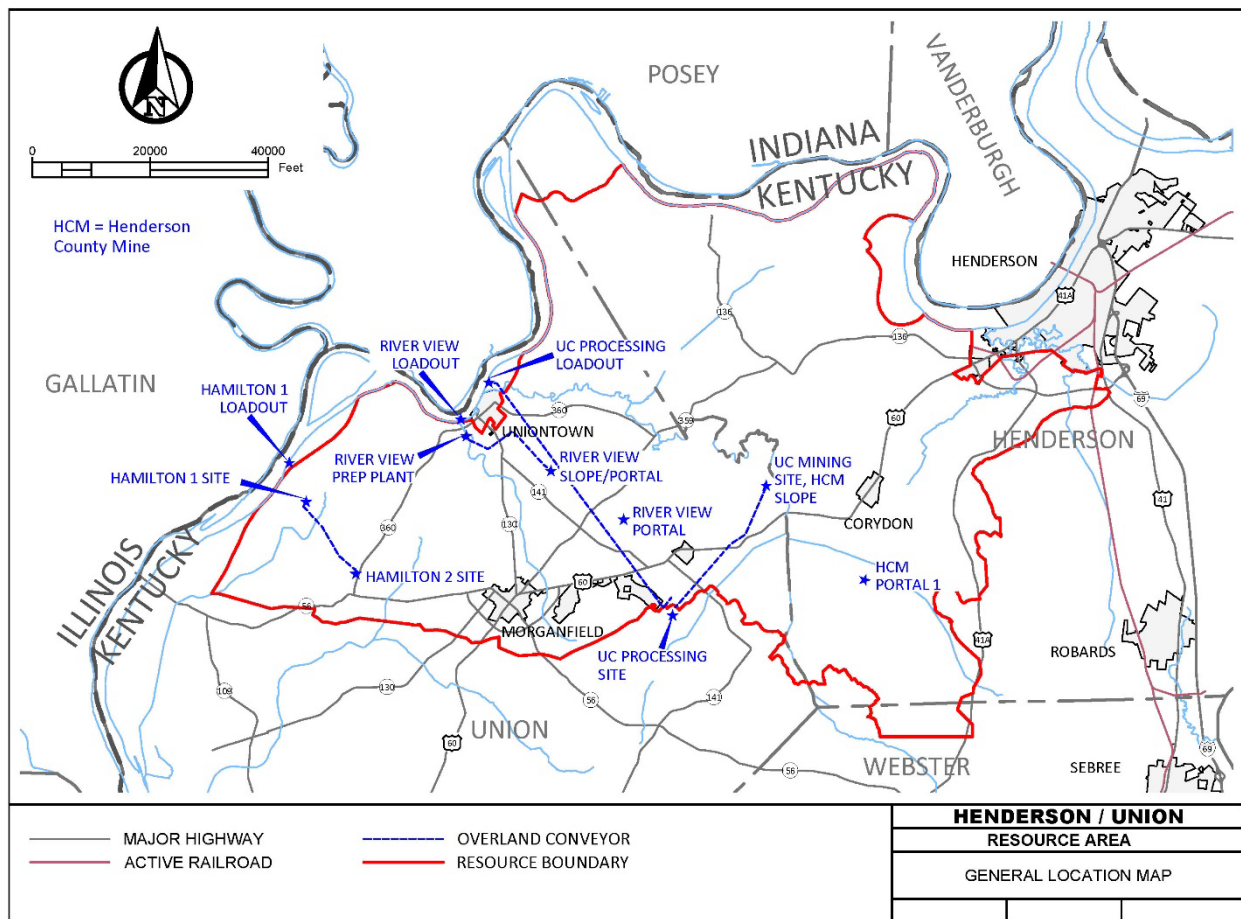
Individual Property Disclosures

We consider the following properties to be material based on multiple factors including, but not limited to, the property's contribution to our overall business and financial condition. Please see *Coal Mineral Resources* and *Coal Mineral Reserves* above for information about the coal mineral resources and reserves held by these material properties. In addition to the following information, TRSs for these material properties with additional information are included as exhibits to this Annual Report on Form 10-K.

Henderson/Union Resources

The Henderson/Union Resources are located in Henderson and Union counties, Kentucky at 37°44'30"N, - 87°46'07"W and we currently have control in over 1,600 tracts encompassing over 127,000 acres. The property is controlled through both fee ownership and leases of the coal. The coal mineral resources are controlled by Alliance Resource Properties. The base leases are with private owners and WKY CoalPlay or its subsidiaries, which are related parties. See "Item 8. Financial Statements and Supplementary Data—Note 21 – Related-Party Transactions" for more information about our WKY CoalPlay transactions. These base leases generally provide for a term that can be extended until exhaustion of the leased coal. Local infrastructure is as follows:

Major Roads: Interstate 69 and US-60,
Railroads: None,
Airport: Evansville Regional Airport (EVV),
Town: Morganfield,
Docks: River View, Hamilton 1, UC Processing, on the Ohio River,
Water: Local municipalities and mine sources,
Electricity: Kentucky Utilities (KU),
Personnel: Regional.



Description

The potential underground mine(s) would utilize room-and-pillar methods operating a heavy media, float/sink style preparation plant. Exploration continues as needed to fulfill possible permitting and development requirements. Multiple access points are available for development. Access is available from the active River View complex, which began production in 2009. All equipment, facilities, infrastructure, and underground development are in good working order and maintained to industry standards. Access at the Hamilton and UC Coal, LLC sites are considered “brownfield” developments. Though some facilities and permitting are in place, significant upgrades to existing infrastructure and new construction would be needed to bring them into good working order that meets industry standards. The property associated with Henderson/Union has no book value as of December 31, 2025 but does have outstanding advanced royalties with WKY CoalPlay or its subsidiaries. See “Item 8. Financial Statements and Supplementary Data—Note 21 – Related-Party Transactions” for more information about advanced royalties that Henderson/Union has with WKY CoalPlay.

Though there is geographic overlap between the Henderson/Union and River View properties, the resources and reserves of each are associated with different coal seams or, if in the same seam, are separated by existing mine works or geologic features into distinct areas. There is no overlap in the resource / reserve estimation.

History

The Henderson/Union property contains resources in the WKY11, WKY7, and WKY6 seams. Island Creek operated mines in the area and controlled a portion of the property. Under a joint venture, Texas Gas Service also controlled a large interest in the mineral rights. Lastly, Peabody and Patriot operated mines in the area and controlled a portion of the reserves. We consolidated control of the property through multiple transactions from 2005 through 2015. Island Creek operated the Ohio #11 mine. Peabody and later Patriot operated the Camp complex and Highland #11 mine to the southeast and east. The WKY11 seam was mined at these locations. No mining has occurred on the property in the WKY7 or WKY6 seams.

In general, all drilling has shown highly consistent coal seams of mineable thickness and quality for the high-sulfur thermal utility market.

Encumbrances

Our credit facility is secured by, among other things, liens against certain Henderson/Union surface properties and coal leases. Documentation of such liens is of record in the Offices of the Henderson and Union County Clerks. Please read “Item 8. Financial Statements and Supplementary Data—Note 12 – Long-term Debt” for more information on our credit facility.

The KYDNR, DMP is responsible for the review and issuance of all permits relative to coal mining and reclamation activities, and financial assurance of comprehensive environmental protection performance standards related to surface and underground coal mining operations. In addition to state mining and reclamation laws, operators must comply with various federal laws relevant to mining.

Geology and Reserves

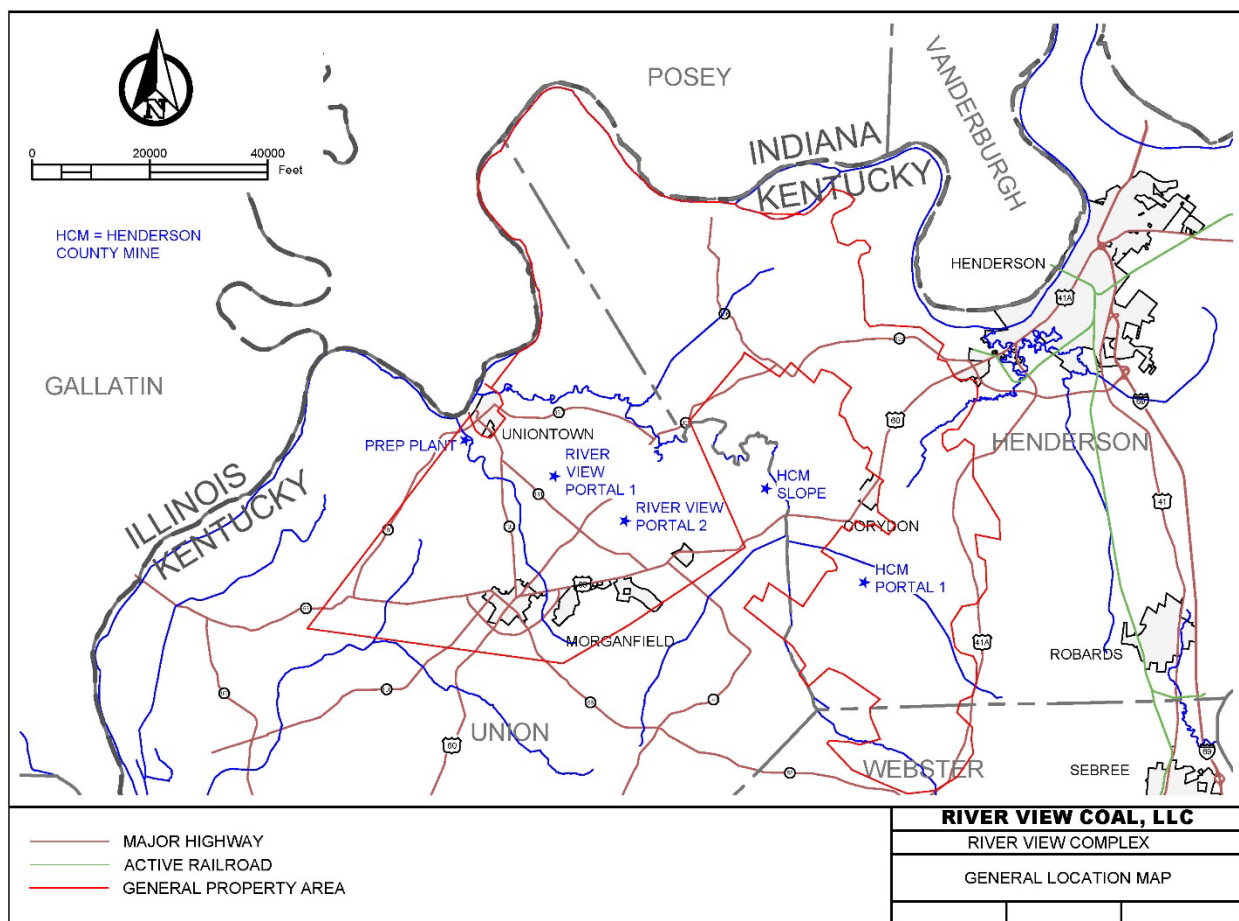
Henderson/Union contains coal resources in three seams ranging in depths from about 100 to 750 feet. The table below summarizes mineral resources as of December 31, 2025, using a cut off thickness of 4.00 feet:

Resources	Tons (in millions)	Thickness (ft)	Quality, Washed, Dry Basis				% Recovery
			% Ash	% Sulfur	Btu	lbs. SO2	In-Seam
Henderson/Union							
Measured Mineral Resources	128.7	4.72	7.71	2.88	13,328	4.31	85.71
Indicated Mineral Resources	229.5	4.62	8.00	2.74	13,307	4.12	87.34
Combined Mineral Resources	358.2	4.66	7.90	2.79	13,315	4.19	86.75
Inferred Mineral Resources	57.0	4.47	7.96	2.56	13,350	3.83	90.67

River View Complex

The River View complex is located in Union County, Kentucky at 37°45'37"N, -87°56'42"W and currently has approximately 93,200 underground acres permitted. The complex is composed of the River View and Henderson County mines along with shared preparation, loadout, and other ancillary facilities. The mineral is controlled through both fee ownership and leases of the coal. The coal mineral reserves are leased or held for lease to the River View complex almost exclusively by Alliance Resource Properties. The River View complex either owns or controls the surface properties upon which its facilities are located including the preparation plant, refuse areas, mine offices, conveyor systems, shafts, and slopes. The base leases are with private owners and generally provide for a term that can be extended until exhaustion of the leased coal. Local infrastructure is as follows:

Major Roads: Interstate 69 and US-60,
Railroads: None,
Airport: Evansville Regional Airport (EVV),
Town: Morganfield,
Docks: River View on the Ohio River,
Water: Union and Henderson County water districts and mine sources,
Electricity: Kentucky Utilities (KU),
Personnel: Regional.



Description

The underground mines are currently in production using room-and-pillar methods utilizing a heavy media, float/sink style preparation plant. Exploration continues as needed to fulfill mining and permitting requirements. The complex began production in 2009. All equipment, facilities, infrastructure, and underground development are in good working order and maintained to industry standards. Total book value of the property and any associated plant and equipment for the River View complex as of December 31, 2025 was \$387.4 million.

Though there is geographic overlap between the River View complex and the Henderson/Union properties, the reserves and resources of each are associated with different coal seams or, if in the same seam, are separated by existing mine works or geologic features into distinct areas. There is no overlap in the resource / reserve estimation.

History

Island Creek operated mines in the area and controlled a portion of the property. Under a joint venture, Texas Gas Service also controlled a large interest in the mineral rights. Lastly, Peabody and Patriot operated mines in the area and controlled a smaller portion of the reserves. We consolidated control of the property through multiple transactions from 2005 through 2015. Island Creek operated the Ohio #11 and Uniontown #9 mines to the west of River View. Island Creek also operated the Hamilton #1 and #2 mines to the southwest. Peabody and later Patriot operated the Camp mines and Highland mines adjacent to the complex. Both the WKY9 and WKY11 seams were mined at these locations. In general, all drilling has shown highly consistent coal seams of mineable thickness and quality for the high-sulfur thermal utility market.

Encumbrances

Our credit facility is secured by, among other things, liens against certain River View complex surface properties and coal leases. Documentation of such liens is of record in the Office of the Union County Clerk. Please read “Item 8. Financial Statements and Supplementary Data—Note 12 – Long-term Debt” for more information on our credit facility.

Accounts receivable generated from the sale of coal mined from this property are collateral for our accounts receivable securitization facility, evidenced by financing statements of record in the Office of the Union County Clerk. Please read “Item 8. Financial Statements and Supplementary Data—Note 12 – Long-term Debt” for more information on our accounts receivable securitization facility.

The KYDNR, DMP is responsible for review and issuance of all permits relative to coal mining and reclamation activities, and financial assurance of comprehensive environmental protection performance standards related to surface and underground coal mining operations. In addition to state mining and reclamation laws, operators must comply with various federal laws relevant to mining. All applicable permits for underground mining, coal preparation and related facilities, and other incidental activities have been obtained and remain in good standing.

Geology and Reserves

The River View complex extracts coal underground from the WKY11 and WKY9 seams with depths ranging from 200 to 500 feet across the reserve. The table below summarizes mineral reserves as of December 31, 2025 using a cut off thickness of 4.00 feet:

Reserves	Tons (in millions)	Thickness (ft)	Quality, Washed, Dry Basis				% Recovery
			% Ash	% Sulfur	Btu	lbs. SO2	In-Seam
River View Complex							
Proven Mineral Reserves	173.4	4.72	8.17	3.20	13,183	4.86	87.53
Probable Mineral Reserves	114.5	4.54	8.08	3.18	13,164	4.84	86.97
Total Mineral Reserves	287.9	4.65	8.13	3.19	13,175	4.85	87.31

Resources associated with the River View complex are included in the Coal Mineral Resources table above.

The River View complex had 303.5 million tons of coal mineral reserves at the end of 2024. The year over year reconciliation is as follows:

River View Complex Yearly Reserve Reconciliation	(in millions)
Tons as of December 31, 2024	303.5
Production	(9.6)
Mine Plan Adjustment	(5.8)
Normal Course Adjustments	(0.2)
Tons as of December 31, 2025	287.9

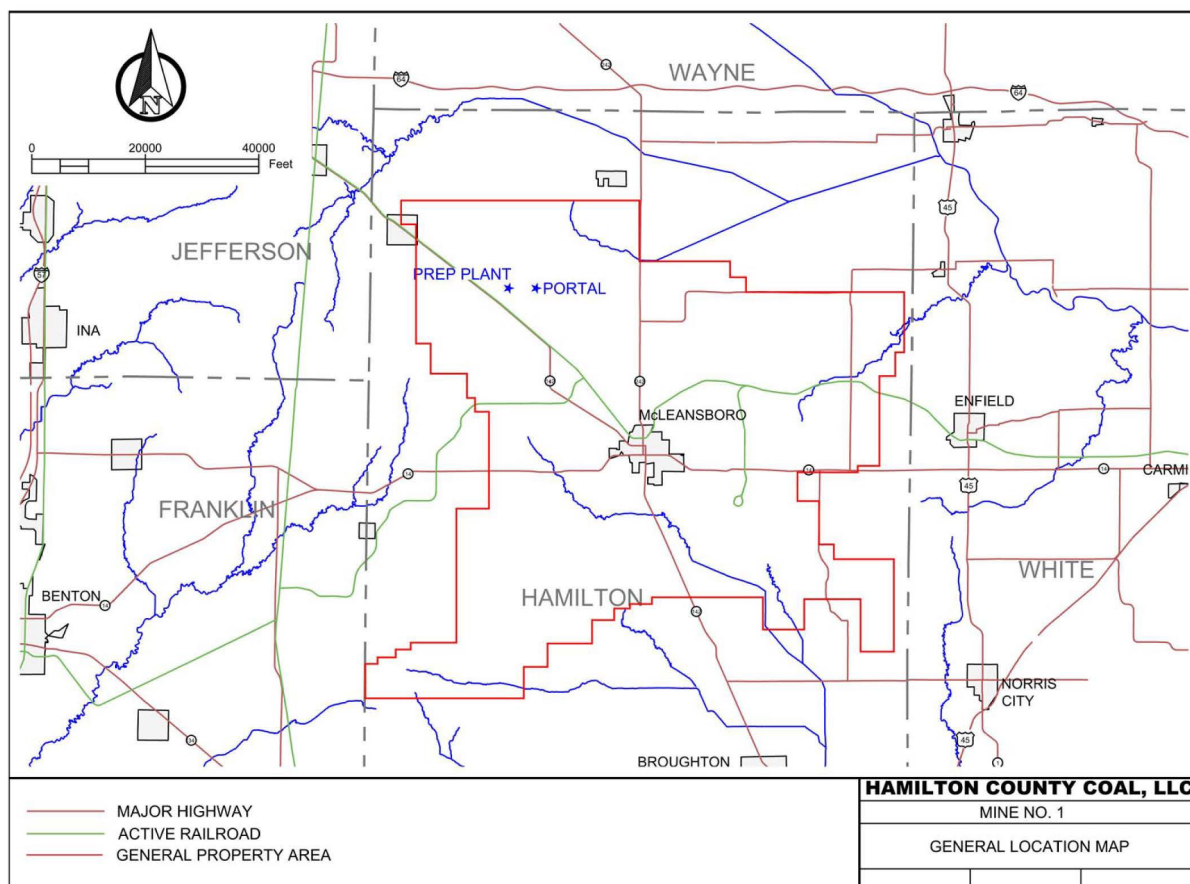
Normal course adjustments are associated with numerous small changes in the geologic/mining model.

Hamilton Mine

Hamilton, a longwall mine located in Hamilton County, Illinois at 38°10'12"N, -88°36'47"W, currently has approximately 23,270 underground acres permitted. The mineral is controlled through both fee ownership and leases of the coal. The coal mineral reserves and resources are leased or held for lease to Hamilton by Alliance WOR Properties, a subsidiary of Alliance Resource Properties. Hamilton either owns or controls the surface properties upon which its facilities are located including the preparation plant, refuse areas, mine offices, conveyor systems, shafts and slopes. The underlying base coal leases are with private owners and are comprised of a large number of leases originally taken by AMAX Coal Company and Old Ben in the mid to late 1970's and early 1980's, leases acquired by Consolidation Coal Company in the late 1980's, and subsequent leases taken directly by White Oak Resources, LLC or affiliated companies and/or Alliance WOR Properties. Local infrastructure is as follows:

Major Roads: Interstate 64,

Railroads: CSX and EVW,
 Airport: Evansville Regional Airport (EVV),
 Towns: McLeansboro and Mt. Vernon,
 Docks: Mount Vernon on the Ohio River,
 Water: Hamilton County Water District and mine sources,
 Electricity: Wayne-White Electric Co-op (WVEC),
 Personnel: Regional.



Description

The underground mine is currently in production using longwall and room-and-pillar methods utilizing a heavy media, float/sink style preparation plant. Exploration continues as needed to fulfill mining and permitting requirements. The mine began production in 2014. All equipment, facilities, infrastructure, and underground development are in good working order and maintained to industry standards. Total book value of the property and any associated plant and equipment for Hamilton as of December 31, 2025 was \$377.3 million.

History

There were no previous operations on the Hamilton reserves property prior to our predecessor, White Oak Resources LLC, who began construction of the mine in 2011. In general, all drilling has shown highly consistent coal seams of mineable thickness and quality for the high-sulfur thermal utility market for the Herrin and Springfield seams.

Encumbrances

Our credit facility is secured by, among other things, liens against certain Hamilton surface properties, coal leases and owned coal. Documentation of such liens is of record in the Office of the Hamilton County Clerk. Please read “Item 8. Financial Statements and Supplementary Data—Note 12 – Long-term Debt” for more information on our credit facility.

The Illinois Department of Natural Resources, Land Reclamation Division is responsible for review and issuance of all permits relative to coal mining and reclamation activities, and financial assurance of comprehensive environmental protection performance standards related to surface and underground coal mining operations. In addition to state mining and reclamation laws, operators must comply with various federal laws relevant to mining. All applicable permits for underground mining, coal preparation and related facilities and other incidental activities have been obtained and remain in good standing.

Geology and Reserves

Hamilton extracts coal underground from the Herrin (Illinois No.6) seam with depths ranging from 900 to 1100 feet across the reserve. The table below summarizes mineral reserves as of December 31, 2025 using a cut off thickness of 4.00 feet:

Reserves	Tons (in millions)	Thickness (ft)	Quality, Washed, Dry Basis				% Recovery
			% Ash	% Sulfur	Btu	lbs. SO2	In-Seam
Hamilton County							
Proven Mineral Reserves	48.7	6.67	8.07	2.88	13,386	4.31	87.01
Probable Mineral Reserves	56.2	6.49	7.95	2.89	13,377	4.32	87.32
Total Mineral Reserves	104.9	6.57	8.01	2.89	13,381	4.32	87.18

Resources associated with Hamilton County are included in the Coal Mineral Resources table above.

The Hamilton mine had 113.8 million tons of coal mineral reserves at the end of 2024. The year over year reconciliation is as follows:

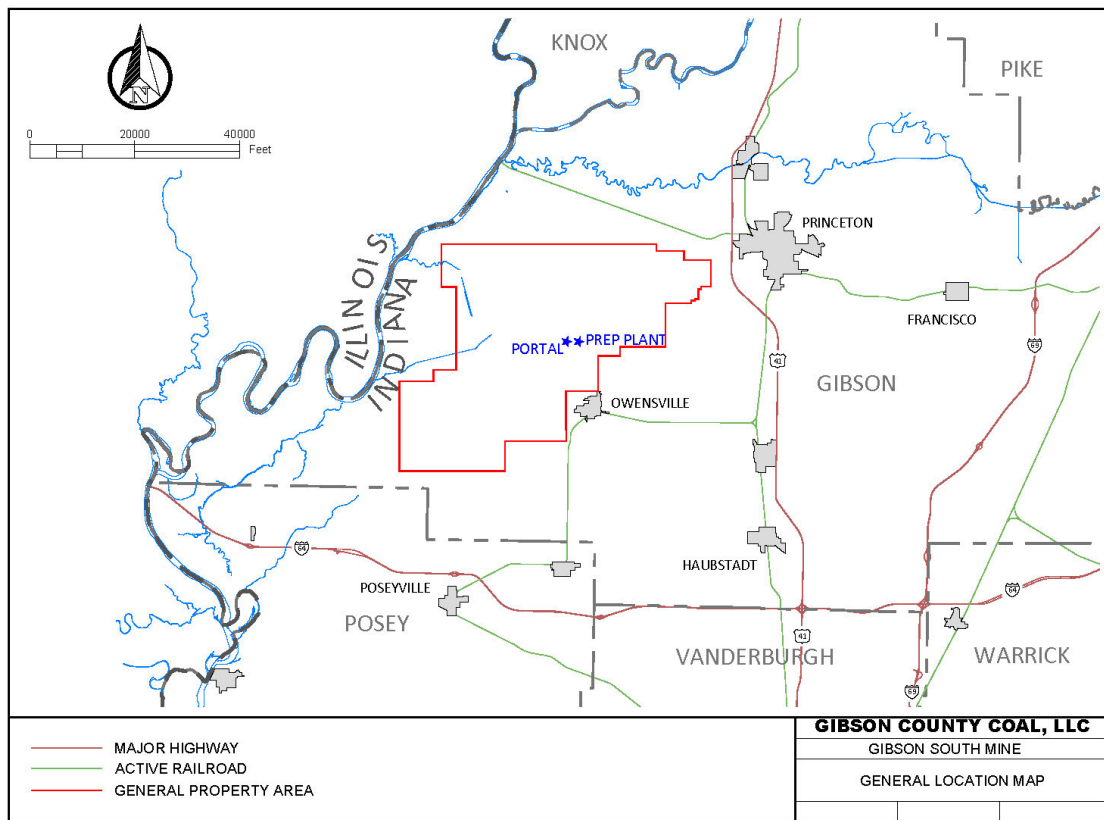
Hamilton County Yearly Reserve Reconciliation	(in millions)
Tons as of December 31, 2024	113.8
Production	(6.5)
Mineral Acquisition / Deletion	(3.1)
Normal Course Adjustments	0.7
Tons as of December 31, 2025	104.9

Normal course adjustments are associated with numerous small changes in the geologic/mining model.

Gibson South Mine

Gibson South is located in Gibson County, Indiana at 38°18'22"N, 87°42'30"W and currently has approximately 41,640 underground acres permitted. The mineral is controlled through both fee ownership and leases of the coal. Leases generally have an initial term with automatic extensions for as long as mining operations are conducted within a described area. Local infrastructure is as follows:

Major Roads: Interstates 69 and 64,
Railroads: CSX and NS,
Airport: Evansville Regional Airport (EVV),
Town: Princeton,
Docks: Mount Vernon on the Ohio River,
Water: Gibson Water, Inc. and well water,
Electricity: Western Indiana Energy REMC,
Personnel: Regional.



Description

The underground mine is currently in production using room-and-pillar methods utilizing a heavy media, float/sink style preparation plant. Exploration continues as needed to fulfill mining and permitting requirements. The mine began production in 2014. All equipment, facilities, infrastructure, and underground development are in good working order and maintained to industry standards. Total book value of the property and any associated plant and equipment for Gibson South as of December 31, 2025 was \$108.9 million.

History

In November 1997, pursuant to (a) Assignment of Underground Coal Leases, (b) Partial Assignment of Underground Coal Leases and (c) Special Corporate Warranty Deed, Old Ben conveyed to MAPCO Land & Development Corporation various coal leases and fee coal interests within a large property boundary located in Gibson County, Indiana. MAPCO Land & Development Corporation changed its name to MAPCO Coal Land & Development Corporation, and MAPCO Coal Land & Development Corporation merged into Alliance Properties effective August 4, 1999.

After the original Old Ben acquisition, Alliance Properties and Gibson continued to acquire additional coal leases and fee coal interests in the area. In addition, beginning in or around 2006, the leases originally acquired from Old Ben began to expire by their terms, and Alliance Properties/Gibson began a program of either amending the expiring leases or entering into new, direct leases with the coal owners. Alliance Properties merged into Gibson on February 19, 2018.

The King's Mine operated to the east and the Wabash Mine operated to the west of the reserve area. In general, all drilling has shown a highly consistent coal seam of mineable thickness and quality for the high-sulfur domestic thermal utility market and low/medium sulfur export market.

Encumbrances

Our credit facility is secured by, among other things, liens against certain Gibson surface properties, coal leases and owned coal. Documentation of such liens is of record in the Office of the Recorder of Gibson County, Indiana. Please read “Item 8. Financial Statements and Supplementary Data—Note 12 – Long-term Debt” for more information on our credit facility.

Accounts receivable generated from the sale of coal mined from this property are collateral for our accounts receivable securitization facility, evidenced by financing statements of record in the Office of the Recorder of Gibson County, Indiana. Please read “Item 8. Financial Statements and Supplementary Data—Note 12 – Long-term Debt” for more information on our accounts receivable securitization facility.

The Indiana Department of Natural Resources, Division of Reclamation is responsible for oversight of active coal mining and reclamation activities, and financial assurance of comprehensive environmental protection performance standards related to surface and underground coal mining operations. In addition to state mining and reclamation laws, operators must comply with various federal laws relevant to mining. All applicable permits for underground mining, coal preparation, and related facilities and other incidental activities have been obtained and remain in good standing.

Geology and Reserves

Gibson South extracts coal underground from the Springfield (Indiana No.5) seam with depths ranging from 450 to 650 feet across the reserve. The table below summarizes mineral reserves as of December 31, 2025 using a cut off thickness of 4.00 feet:

Reserves	Tons (in millions)	Thickness (ft)	Quality, Washed, Dry Basis				% Recovery
			% Ash	% Sulfur	Btu	lbs. SO2	In-Seam
Gibson South							
Proven Mineral Reserves	25.1	5.80	7.28	2.15	13,438	3.19	94.39
Probable Mineral Reserves	7.1	5.38	8.41	2.75	13,256	4.16	91.49
Total Mineral Reserves	32.2	5.71	7.53	2.28	13,398	3.40	93.75

Resources associated with Gibson South are included in the Coal Mineral Resources table above.

The Gibson South mine had 40.0 million tons of coal mineral reserves at the end of 2024. The year over year reconciliation is as follows:

Gibson South Yearly Reserve Reconciliation	(in millions)
Tons as of December 31, 2024	40.0
Production	(5.5)
Mineral Acquisition / Deletion	2.3
Mine Plan Adjustment	(4.4)
Normal Course Adjustments	(0.2)
Tons as of December 31, 2025	32.2

Normal course adjustments are associated with numerous small changes in the geologic/mining model.

Tunnel Ridge Mine

Tunnel Ridge, located at 40°09'17" N, -80°39'26"W, is an underground longwall mine in the Pittsburgh No. 8 seam and currently has approximately 23,870 underground acres permitted. The mineral is controlled through both fee ownership and leases of the coal. The coal mined and to be mined by Tunnel Ridge is leased from Alliance Resource Properties and third parties. Prior to January 29, 2026, certain of the coal mined and to be mined by Tunnel Ridge had been leased from the Craft Foundations. On January 29, 2026, Alliance Resource Properties purchased all of the ownership interests in these coal reserves together with surface rights from the Craft Foundations. Please read "Item 8. Financial Statements and Supplemental Data— Note 12 – Long-term Debt and —Note 21 – Related-Party Transactions" for additional information on related-party leases and transactions. Tunnel Ridge either owns or controls the surface properties upon which its facilities are located, including the preparation plant, refuse areas, mine offices, conveyor systems, shafts and slopes. Local infrastructure is as follows:

Major Roads: Interstate 70,

Railroads: None,

Airport: Pittsburgh International Airport (PIT),

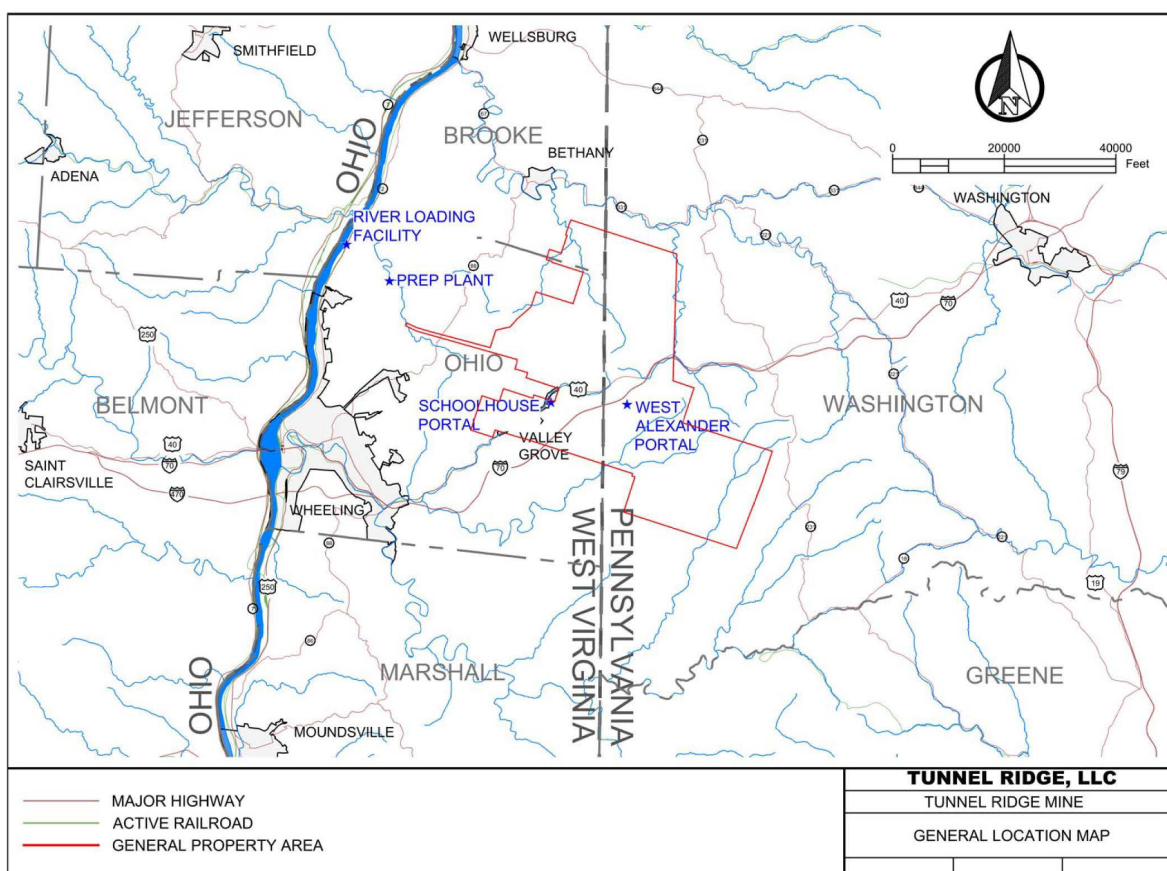
Town: Wheeling,

Docks: Tunnel Ridge on the Ohio River,

Water: Municipal water districts and mine sources,

Electricity: American Electric Power (AEP), West Penn Power (WPP),

Personnel: Regional.



Description

The underground mine is currently in production using longwall and room-and-pillar methods utilizing a heavy media, float/sink style preparation plant. Exploration continues as needed to fulfill mining and permitting requirements. The mine began production in 2010. All equipment, facilities, infrastructure, and underground development are in good working

order and maintained to industry standards. Total book value of the property and any associated plant and equipment for Tunnel Ridge as of December 31, 2025 was \$330.9 million.

History

Valley Camp operated mines on the property prior to Tunnel Ridge's operations. In general, all drilling has shown a highly consistent coal seam of mineable thickness and quality for the high-sulfur thermal utility market.

Encumbrances

Our credit facility is secured by, among other things, liens against certain Tunnel Ridge surface properties, coal leases and owned coal. Documentation of such liens is of record in the Office of the County Commission of Ohio County, West Virginia and the Office of the Recorder of Deeds of Washington County, Pennsylvania. Please read "Item 8. Financial Statements and Supplementary Data—Note 12 – Long-term Debt" for more information on our credit facility.

Accounts receivable generated from the sale of coal mined from this property are collateral for our accounts receivable securitization facility, evidenced by financing statements of record in the Office of the County Commission of Ohio County, West Virginia and the Office of the Recorder of Deeds of Washington County, Pennsylvania. Please read "Item 8. Financial Statements and Supplementary Data—Note 12 – Long-term Debt" for more information on our accounts receivable securitization facility.

Tunnel Ridge is located on the West Virginia / Pennsylvania State boundary, operating in each state. As such, regulatory requirements must be met pertaining to mining facilities located in each state.

For operations in West Virginia, the WVDEP is the regulatory authority over mining activities. Within the WVDEP, the Division of Mining and Reclamation is responsible for review and issuance of all permits relative to coal mining and reclamation activities, and financial assurance of comprehensive environmental protection performance standards related to surface and underground coal mining operations.

For operations in Pennsylvania, the PADEP is the regulatory authority over mining activities. Within the PADEP, the Bureau of District Mining Operations is responsible for review and issuance of all permits relative to coal mining and reclamation activities, and financial assurance of comprehensive environmental protection performance standards related to surface and underground coal mining operations.

In addition to state mining and reclamation laws, operators must comply with various federal laws relevant to mining. All applicable permits for underground mining, coal preparation, and related facilities and other incidental activities have been obtained and remain in good standing.

Geology and Reserves

Tunnel Ridge extracts coal underground from the Pittsburgh No.8 seam with depths ranging from 300 to 975 feet across the reserve. The table below summarizes mineral reserves as of December 31, 2025 using a cut off thickness of 4.00 feet:

Reserves	Tons (in millions)	Thickness (ft)	Quality, Washed, Dry Basis				% Recovery
			% Ash	% Sulfur	Btu	lbs. SO2	In-Seam
Tunnel Ridge							
Proven Mineral Reserves	59.9	7.28	9.38	3.55	13,546	5.23	68.38
Probable Mineral Reserves	49.2	7.51	9.14	3.39	13,562	4.99	70.88
Total Mineral Reserves	109.1	7.38	9.27	3.48	13,553	5.12	69.51

Resources associated with Tunnel Ridge are included in the Coal Mineral Resources table above.

The Tunnel Ridge mine had 111.0 million tons of coal mineral reserves at the end of 2024. The year over year reconciliation is as follows:

Tunnel Ridge Yearly Reserve Reconciliation	(in millions)
Tons as of December 31, 2024	111.0
Production	(5.2)
Mine Plan Adjustment	3.7
Normal Course Adjustments	(0.4)
Tons as of December 31, 2025	109.1

Normal course adjustments are associated with numerous small changes in the geologic/mining model.

OIL & GAS RESERVES

Summary of Oil & Gas Reserves

Our mineral interests are primarily located in three basins, which also represent our areas of focus for future development. These include the Permian (Delaware and Midland), Anadarko (SCOOP/STACK) and Williston (Bakken) Basins. At December 31, 2025, we had 51,233 developed and undeveloped net acres held at a weighted average royalty of 17.0%. Our net acres standardized to 1/8th royalty equate to 69,880 net royalty acres, including 3,962 net royalty acres owned through our equity interest in AllDale III.

The following table presents our estimated net proved oil & gas reserves, including our share of reserves attributable to our equity interest in AllDale III, as of December 31, 2025 based on the reserve report prepared by our internal engineering team and reserve information provided by AllDale III. The reserve report and reserve information have been prepared in accordance with the rules and regulations of the SEC. All of our proved reserves are located in the continental United States.

	As of December 31, 2025			
	Crude Oil (MBbl)	Natural Gas (MMcf)	Natural Gas Liquids (MBbl)	Total (MBOE) (2)
Estimated proved developed reserves	9,159	60,732	7,754	27,034
Estimated proved undeveloped reserves	1,438	5,324	766	3,091
Total estimated proved reserves (1)	10,597	66,056	8,520	30,125

(1) Proved reserves of approximately 2,037 MBOE were attributable to noncontrolling interests as of December 31, 2025.

(2) Natural gas reserve volumes are converted to BOE based on a 6:1 ratio: 6 Mcf of natural gas converts to one BOE.

Estimates of reserves as of December 31, 2025 were prepared using product prices equal to the unweighted arithmetic average of the first-day-of-the-month market price for each month in the period from January through December 2025. The average realized product prices weighted by production over the remaining lives of the properties are \$64.89/Bbl for oil, \$1.40/Mcf of natural gas and \$18.29 per barrel of NGL. These prices are adjusted for energy content, associated average differential and transportation deducts by producing area to arrive at the net realized prices by product. For 2025, NGL prices averaged approximately 33% of the posted oil prices during the course of the year with an additional \$3.38/Bbl deducted for transportation costs.

The following table summarizes our changes in proved undeveloped reserves (in MBOE):

Beginning balance, January 1, 2025	2,832
Acquisitions of proved undeveloped reserves	135
Transfers of PUDs to estimated proved developed	(815)
Extensions and discoveries	1,492
Revisions of previous estimates	(553)
Ending balance, December 31, 2025	<u>3,091</u>

During the year ended December 31, 2025, PUD reserves were increased as a result of the acquisition of oil & gas mineral interests during the year primarily from the Elk Range Acquisition discussed in more detail in “Item 8. Financial Statements and Supplementary Data—Note 4 – Acquisitions.”

During the year ended December 31, 2025, PUD reserves were reduced as a result of conversion to proved developed reserves primarily in the Permian and Anadarko basins as the result of well completions during the year.

Extensions and discoveries contributed to an increase in PUD reserves during the year ended December 31, 2025 primarily as the result of permitting activities in the Permian Basin.

Revisions of previous estimates resulted in a decline due primarily to revisions to quantity estimates.

As a mineral interest owner we have no transparency into or control over the operators’ investments and operational progress to convert PUDs to proved developed producing reserves nor do we have insight into the operators’ drilling plans. Since we do not have insight into the operators’ drilling plans, we use active drilling permits as evidence of economic viability and intention to expend capital to develop reserves within five years as there is generally a statutory two-year timeframe associated with permits. We do not incur capital expenditures or lease operating expenses in connection with the development of our PUDs, which costs are borne entirely by the operators. As a result, during the year ended December 31, 2025, we did not have any expenditures to convert PUDs to proved developed producing reserves. PUDs that have not been developed within two years of permitting are reviewed and removed from proved reserves as necessary. Because we remove PUDs from proved reserves that have not been developed within two years of initial classification as proved reserves, we have no material PUDs that are not expected to be developed within five years of initial classification as proved reserves. Our average permit to first sales timeframe is 381 days. For our 2025 reserve reporting, we had scheduled all PUD locations to be drilled within a two year timeframe using the average historical development pacing on our acreage in the individual basins in which we own mineral interests. As of December 31, 2025, approximately 10.26% of our total proved reserves were classified as PUDs.

Evaluation and Review of Reserves

Numerous uncertainties are inherent in estimating reserve volumes and values, and the estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of the reserves may vary significantly from the original estimates.

Under SEC rules, proved reserves are those quantities of oil & gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a “high degree of confidence that the quantities will be recovered.” All of our proved reserves as of December 31, 2025 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil & gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil & gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods:

- (1) performance-based methods,
- (2) volumetric-based methods and
- (3) analogy.

These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. The proved reserves for our properties were estimated by performance methods, analogy or a combination of both methods. Performance methods include, but may not be limited to, decline curve analysis, which utilize extrapolations of available historical production data. The analogy method was used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate.

To estimate economically recoverable proved reserves and related future net cash flows, our engineering team considered many factors and assumptions, including the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and the SEC pricing requirements and forecasts of future production rates. To establish reasonable certainty with respect to our estimated proved reserves, the technologies and economic data used in the estimation of our proved reserves included production and well test data, downhole completion information, geologic data, electrical logs, and radioactivity logs.

Non-producing reserve estimates, for both developed and undeveloped properties, are based on regional type curve methodologies by reservoir or productive bench. These methods provide a relatively high degree of accuracy for predicting proved developed non-producing and undeveloped reserves for our properties, due to the mature nature of properties targeted for development and an abundance of historical production data on which we base statistical average type forecasts.

New drills on our acreage include planned drills, wells currently drilling, and/or permitted wells. For each new drill, a reserve category of proved developed non-producing or PUD is assigned based on whether the location has been spud or permitted. Generally, we recognize a location as a PUD when it has been permitted by the operator and a PUD becomes a proved developed non-producing reserve when the operator has spud that well to begin drilling operations.

Drill scheduling is determined by historical development pacing on our acreage in each basin and it is assumed that future pacing will mirror that of the historical pace. This projection is then adjusted to take into account anticipated commodity prices and other industry economic factors which tend to either reduce or increase future development pacing. First, known completed locations are developed in chronological order based on state filings or publicly sourced completion data. The development schedule for these locations estimates the turn-in-line rate of these locations due to production data lag. Second, spud locations with unknown completion status are scheduled based on the historical spud to completion time within each basin. Third, permitted locations, without development timing, are scheduled in chronological order by filing date.

Excluding our share of proved reserves held by AllDale III, our 2025 year-end estimate of proved reserves were prepared by our internal engineering team. Our engineering team works to ensure the integrity, accuracy, and timeliness of the data used to calculate our estimated proved reserves. Our proved reserve estimates, with the exception of AllDale III, which comprise 3.3% of our total proved reserves, were audited by CGA. Our engineering team met with CGA periodically during the period covered by the above referenced reserve report to discuss the assumptions and methods used in the reserve estimation process. Our engineering team provided historical information to CGA for our properties, such as oil & gas production, well test data, and realized commodity prices. Our engineering team also provided ownership interest information with respect to our properties. Our internal petroleum engineer, primarily responsible for overseeing the petroleum reserves preparation, has over 20 years of engineering and operations experience in the oil & gas sector and a Bachelor of Science in Petroleum Engineering.

The preparation of our proved reserve estimates are completed in accordance with our internal control procedures. These procedures, which are intended to ensure reliability of reserve estimations, include the following:

- review and verification of historical data, which is based on actual production as reported by the operators;
- verification of property ownership by our land department;
- review of all our reported proved reserves semi-annually including the review of all significant reserve changes and proved undeveloped reserves additions by our internal petroleum engineer;
- internally prepared reserve estimates compared to reserves audit by CGA;
- review of changes in reserves semi-annually by our internal petroleum engineer and by senior management; and
- no employee's compensation is tied to the amount of reserves booked.

CGA, an independent third-party petroleum engineering firm, does not own an interest in any of our properties and is not employed on a contingent basis. When compared on a well-by-well basis, some of our estimates are greater and some are less than the CGA estimates. CGA is satisfied with our methods and procedures used to prepare the December 31, 2025 reserve estimates and future revenue, and noted nothing of an unusual nature that would cause CGA to take exception with the estimates, in the aggregate, prepared by us. CGA's audit report with the respect to our proved reserve estimates as of December 31, 2025 is included as an exhibit to this Annual Report on Form 10-K.

CGA was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-693. Within CGA, the technical person primarily responsible for auditing the estimates meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and is proficient in judiciously applying industry-standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Acreage Concentration

Below is a chart reflecting our gross, net mineral and net royalty acreage associated with our mineral interests in each of our primary basins as of December 31, 2025.

Basin	Developed Acreage			Undeveloped Acreage		
	Gross	Net Mineral	Net Royalty	Gross	Net Mineral	Net Royalty
Permian Basin	459,462	13,484	18,157	486,516	14,278	19,222
Anadarko Basin	153,083	5,516	7,813	322,902	11,635	16,497
Williston Basin	129,807	2,145	2,841	108,083	1,786	2,371
Other	21,867	798	1,030	43,598	1,591	1,949
Total	764,219	21,943	29,841	961,099	29,290	40,039

The 51,233 developed and undeveloped net mineral acres in the table above represent the number of acres that are owned for the mineral rights under a given tract of land, whereas the 69,880 developed and undeveloped net royalty acres are our net mineral acres normalized to 1/8th royalty leasing terms. As an example, if 100 net mineral acres were leased for a 25% royalty, this would be equivalent to 200 net royalty acres, normalized to 1/8th royalty ($100 \times .25/.125 = 200$).

Our royalty interests are predominately perpetual mineral interests. As a mineral interest owner, we generally hold our acreage in perpetuity and not through a lease. As a result, our undeveloped acreage is not generally subject to expiration. Our royalty interests do include a small portion that come in the form of overriding royalties (ORRI) that are subject to lease terminations once the wells on that lease cease to produce oil & gas in commercial quantities. As a result, we do have limited long-dated lease expiration exposure; however, nearly all of these ORRIs are part of leases with proved developed producing reserves and ongoing development that we believe will be sufficient to maintain these leases for decades.

Oil & Gas Production Prices and Production Costs

For the year ended December 31, 2025, 44.5% of our production and 75.2% of our oil & gas revenues were related to oil production and sales, respectively. The following table sets forth information regarding production of oil & gas including our equity investment in AllDale III and certain price and cost information for each of the periods indicated:

	Year Ended December 31,		
	2025	2024	2023
Production:			
Oil (MBbls)	1,677	1,543	1,462
Natural gas (MMcf)	7,097	6,758	6,161
Natural gas liquids (MBbls)	908	850	726
BOE (MBbls)			
Permian Basin	3,034	2,755	2,496
Anadarko Basin	415	413	409
Williston Basin	174	226	170
Other	145	126	140
Total BOE	3,768	3,520	3,215
Average Realized Prices:			
Oil (per Bbl)	\$ 64.12	\$ 75.03	\$ 77.40
Natural gas (per Mcf)	\$ 2.22	\$ 1.43	\$ 2.03
Natural gas liquids (per Bbl)	\$ 21.74	\$ 20.44	\$ 23.15
BOE (MBbls)	\$ 37.96	\$ 40.58	\$ 44.32
Unit cost per BOE:			
Production and ad valorem taxes	\$ 3.87	\$ 4.29	\$ 4.37

Productive Wells

As of December 31, 2025, our productive wells were as follows:

Productive Wells							
Horizontal				Vertical			
Oil		Gas		Oil		Gas	
Gross	Net	Gross	Net	Gross	Net	Gross	Net
11,916	37	1,207	4	5,272	21	534	2

Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. We do not own any material working interests in any wells and therefore use our net revenue interest to determine our net wells.

Drilling Results

As a holder of mineral interests, we generally do not receive information as to whether wells drilled on the acreage associated with our mineral interests are classified as exploratory or as developmental wells. We are not aware of any dry holes drilled on the acreage associated with our mineral interests during the year ended December 31, 2025. Based on our net revenue interests, 4, 9 and 10 net wells were drilled on our interests during the years ended December 31, 2025, 2024 and 2023, respectively.

ITEM 3. LEGAL PROCEEDINGS

From time to time, we are party to litigation matters incidental to the conduct of our business. It is the opinion of management that the ultimate resolution of our pending litigation matters will not have a material adverse effect on our financial condition, results of operation or liquidity. However, we cannot assure you that disputes or litigation will not arise or that we will be able to resolve any such future disputes or litigation in a satisfactory manner. From time to time, we are also a party to certain environmental legal proceedings involving governmental authorities. Our threshold for disclosing material environmental legal proceedings involving a governmental authority where potential monetary sanctions are involved is \$1.0 million. The information under “General Litigation” and “Other” in “Item 8. Financial Statements and Supplementary Data—Note 16 – Commitments and Contingencies” is incorporated herein by this reference.

Litigation was initiated in November 2019 in the U.S. District Court for the Western District of Kentucky (*Branson v. Webster County Coal, LLC, et al.*) against certain of our subsidiaries in which the plaintiffs allege violations of the Fair Labor Standards Act and state law due to alleged failure to compensate for time “donning” and “doffing” equipment and to account for certain bonuses in the calculation of overtime rates and pay. A similar lawsuit was initiated in March 2020 in the U.S. District Court for the Eastern District of Kentucky (*Brewer v. Alliance Coal, LLC, et al.*). Subsequently, four additional lawsuits making similar allegations were initiated against certain of our subsidiaries: filed March 4, 2021 in the Circuit Court for Hopkins County, Kentucky (*Johnson v. Hopkins County Coal, LLC, et al.*); filed April 6, 2021 in the U.S. District Court for the Northern District of West Virginia (*Rettig v. Mettiki Coal WV, LLC, et al.*); filed April 9, 2021 in the U.S. District Court for the Southern District of Illinois (*Cates v. Hamilton County Coal, LLC, et al.*); and filed April 13, 2021 in the U.S. District Court for the Southern District of Indiana (*Prater v. Gibson County Coal, LLC, et al.*). The plaintiffs in these cases sought class and collective action certification, which we opposed. The plaintiffs sought to recover alleged compensatory, liquidated and/or exemplary damages for the alleged underpayment, and costs and fees that potentially may be recoverable under applicable law. In April 2024, we entered into a settlement agreement with the plaintiffs pursuant to which we agreed to settle all six cases for \$15.3 million. In November 2025, the court approved the parties’ settlement and settlement checks were distributed in December 2025. Following an acceptance period, the parties will file a joint notice of the acceptance period’s conclusion and a notice of voluntary dismissal with prejudice.

ITEM 4. MINE SAFETY DISCLOSURES

Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in Exhibit 95.1 to this Annual Report on Form 10-K.

PART II

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

The common units representing limited partners' interests are listed on the NASDAQ Global Select Market under the symbol "ARLP." The common units began trading on August 20, 1999. There were approximately 58,402 record holders of common units at December 31, 2025.

Available cash with respect to each quarter may, at the discretion of our general partner, be distributed to the limited partners as of a record date selected by the general partner. "Available cash," as defined in our partnership agreement, generally means, with respect to any quarter, all cash on hand at the end of each quarter, plus working capital borrowings after the end of the quarter, less cash reserves in the amount necessary or appropriate in the reasonable discretion of our general partner to (a) provide for the proper conduct of our business, (b) comply with applicable law or any debt instrument or other agreement of ours or any of our affiliates, and (c) provide funds for distributions to unitholders for any one or more of the next four quarters.

Equity Compensation Plans

The information relating to our equity compensation plans required by Item 5 is incorporated by reference to such information as set forth in "Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters" contained herein.

Unit Repurchase Program

On May 31, 2018, ARLP announced that the Board of Directors approved the establishment of a unit repurchase program authorizing ARLP to repurchase up to \$100.0 million of its outstanding limited partner common units. In January 2023, the Board of Directors authorized a \$93.5 million increase to the unit purchase program, which had \$6.5 million of available capacity at the time, authorizing us to be able to repurchase up to a total of \$100.0 million of ARLP common units from that date. The unit repurchase program is intended to enhance ARLP's ability to achieve its goal of creating long-term value for its unitholders and provides another means, along with quarterly cash distributions, of returning cash to unitholders. The program has no time limit and ARLP may repurchase units from time to time in the open market or other privately negotiated transactions. The unit repurchase program authorization does not obligate ARLP to repurchase any dollar amount or number of units, and repurchases may be commenced or suspended from time to time without prior notice.

During the three months ended December 31, 2025, we did not repurchase and retire any units. Since the inception of the unit repurchase program, we have repurchased and retired 6,390,446 units at an average unit price of \$17.67 for an aggregate purchase price of \$112.9 million. The remaining authorized amount for unit repurchases under this program was \$80.6 million as of December 31, 2025.

ITEM 6. [Reserved]

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

The following discussion of our financial condition and results of operations should be read in conjunction with the historical financial statements and notes thereto included in "Item 8. Financial Statements and Supplementary Data" where you can find more detailed information in "Note 1 – Organization and Presentation" and "Note 2 – Summary of Significant Accounting Policies" regarding the basis of presentation supporting the following financial information.

Executive Overview

Organization

We are a diversified natural resource company that generates operating and royalty income from the production and marketing of coal to major domestic utilities, industrial users and international customers, as well as royalty income from oil & gas mineral interests located in key producing regions across the United States. Our core objective is to maximize the value of our mineral asset base—both through coal production from our mining operations and through the leasing and development of our coal and oil & gas mineral interests. Our strategy is to provide reliable, baseload fuel for electricity generating customers while positioning the Partnership for long-term growth through investments in energy and related infrastructure. Leveraging our relationships with electric utilities, industrial customers, and government partners, we intend to pursue strategic opportunities that complement our operational strengths. We believe our diverse resource portfolio and targeted investments will continue to create long-term value for our unitholders.

We are the second largest coal producer in the eastern United States and as of December 31, 2025, we operated seven underground mining complexes across Illinois, Indiana, Kentucky, Maryland, Pennsylvania, and West Virginia and a coal-loading terminal on the Ohio River in Indiana. We manage and report our coal operations under two regions, Illinois Basin and Appalachia. We market our coal production to major domestic and international utilities and industrial customers.

We also own mineral and royalty interests in approximately 70,000 net royalty acres, including approximately 4,000 net royalty acres attributable to our equity interest in AllDale III, in premier oil & gas producing regions in the United States, primarily the Permian, Anadarko, and Williston Basins. While we own both oil & gas mineral and royalty interests, we refer to them collectively as mineral interests throughout our discussions of our business as the majority of our holdings are mineral interests. We market our oil & gas mineral interests for lease to operators in those regions and generate royalty income from their development of those mineral interests. We expect reserve additions and the related cash flows to grow through further development of our existing mineral interests as well as acquisitions of additional mineral interests.

We also hold coal mineral reserves and resources in Illinois, Indiana, Kentucky, Pennsylvania and West Virginia. Substantially all of our coal mineral resources and a majority of our coal mineral reserves are owned or leased by Alliance Resource Properties, which are (a) leased or subleased to our mining complexes or (b) near other internal and external coal mining operations but not yet leased. We generate intercompany royalty income through the leasing and development of our coal mineral reserves and resources.

Beyond our core mineral platform, we have invested in growth-oriented businesses and energy-related technologies. Our subsidiary, Matrix Group, develops and markets industrial, mining and technology products and services worldwide and our subsidiary, Bitiki, mines bitcoin. We have also made investments in emerging energy and infrastructure opportunities, including Infinitum, NGP ET IV and Gavin Generation.

Please see "Item 1. Business and Item 2. Properties" for a more detailed discussion of our various businesses.

As of December 31, 2025, we had four reportable segments: Illinois Basin Coal Operations, Appalachia Coal Operations, Oil & Gas Royalties and Coal Royalties. We also have an "all other" category referred to as Other, Corporate and Elimination. Our two coal operations reportable segments correspond to major coal producing regions in the eastern United States with similar economic characteristics including coal quality, geology, coal marketing opportunities, mining and transportation methods and regulatory issues. Our Oil & Gas Royalties reportable segment includes our oil & gas mineral interests. Our Coal Royalties reportable segment includes coal mineral reserves and resources owned or leased by Alliance Resource Properties.

- The Illinois Basin Coal Operations reportable segment includes (a) the Gibson mining complex, (b) the Warrior mining complex, (c) the River View mining complex and (d) the Hamilton mining complex. The segment also includes activity associated with support services and our non-operating mining complexes.
- The Appalachia Coal Operations reportable segment includes (a) the Mettiki mining complex, (b) the Tunnel Ridge mining complex and (c) the MC Mining mining complex.
- The Oil & Gas Royalties reportable segment includes oil & gas mineral interests held by Alliance Minerals as well as our equity interests in AllDale III.
- The Coal Royalties reportable segment includes substantially all of our coal mineral resources and the majority of our coal mineral reserves owned or leased by Alliance Resource Properties. Approximately 73% of the coal sold by our coal operations' mines was leased from our Coal Royalties entities for the year ended December 31, 2025.
- Other, Corporate and Elimination includes marketing and administrative activities, the Matrix Group, Bitiki (which holds our crypto-mining activities), our non-oil & gas investments, Wildcat Insurance (which assists the ARLP Partnership with its insurance requirements), and AROP Funding and Alliance Resource Finance Corporation (both discussed in "Item 8. Financial Statements and Supplementary Data – Note 12 – Long-Term Debt"), and other miscellaneous activities. The eliminations included in Other, Corporate and Elimination primarily represent the intercompany coal royalty transactions described above between our Coal Royalties reportable segment and our coal operations' mines.

Risks and Uncertainties

We face a variety of risks and uncertainties that management considers in the operation and planning of our businesses, which could affect our financial position and results of operations. For additional information regarding our risks and uncertainties that affect our business and the industries in which we operate, see "Item 1A. Risk Factors".

Business Strategy

Our primary business strategy is to create sustainable, capital-efficient growth in available cash to maximize unitholder returns by:

- expanding our coal operations by adding and developing mines and coal mineral reserves and resources in existing, adjacent or neighboring properties;
- extending the lives of our mining operations through the acquisition and development of coal mineral reserves and resources using our existing infrastructure;
- continuing to make productivity improvements to remain a low-cost coal producer in each region in which we operate;
- strengthening our position with existing and future customers by offering a broad range of coal qualities, transportation alternatives and customized services;
- developing strategic relationships to take advantage of opportunities within the coal and oil & gas industries and in other industries;
- continuing to make investments in oil & gas mineral interests in various geographic locations within producing basins in the continental United States;
- strengthen and expand our technology company, Matrix Group, as we continue to develop and market industrial, mining and technology products and services worldwide; and
- continuing to identify and make strategic investments in the growth and development of energy and related infrastructure opportunities to leverage our core competencies and build platforms for future lines of business with long-term growth and cash flow generation.

How We Evaluate Our Performance

Our management uses a variety of financial and operational measurements to analyze our performance. Primary measurements include the following: (1) coal volumes; (2) coal sales; (3) oil & gas volumes; (4) oil & gas royalties; (5) intercompany coal royalties; (6) Segment Adjusted EBITDA Expense; and (7) Segment Adjusted EBITDA.

Coal Volumes

We monitor and analyze our coal sales and production volumes of our mining complexes. We also regularly compare budgeted to actual volumes reported and investigate variances. Coal sales volumes are used as a measure of performance as well as an indicator of inventory levels at our complexes when viewed in connection with coal production volumes. Coal production volumes give us an insight into the capacity usage of our complexes and are a source of expenses on a per ton basis as fixed costs are spread across the production.

Coal Sales

We monitor and analyze coal sales as a measure of performance of our coal mining operations. We review coal sales and coal sales per ton at a consolidated level as well as at the mining complex level. We calculate coal sales per ton by dividing coal sales by coal sales volumes. We regularly compare budgeted coal sales and coal sales per ton to actual coal sales and coal sales per ton and investigate unexpected variances.

Oil & Gas Volumes

We monitor and analyze our oil & gas royalty volumes from the various basins that comprise our portfolio of mineral interests. We also regularly compare budgeted to actual volumes reported and investigate variances. Oil & gas royalty volumes on a BOE basis are used as a measure of performance and give us insight into the production activity of our operators.

Oil & Gas Royalties

We monitor and analyze our oil and gas royalties in total and on a price per BOE from the various basins that comprise our portfolio of mineral interests. We also regularly compare budgeted to actual volumes and investigate unexpected variances. We define price per BOE as total oil & gas royalties divided by BOE produced. We review oil & gas royalties and price per BOE to evaluate performance against budget and for trend analysis.

Intercompany Coal Royalties

We monitor and analyze our coal royalties, coal royalty volumes and coal royalties per ton at our various mining subsidiaries for coal leased by Alliance Resource Properties for trend analysis. We define coal royalties per ton as total coal royalties divided by royalty tons sold.

Segment Adjusted EBITDA Expense

We define Segment Adjusted EBITDA Expense (a non-GAAP financial measure) as the sum of operating expenses, coal purchases and other expenses as adjusted to remove certain items from operating expenses that we characterize as unrepresentative of our ongoing operations. Transportation expenses are excluded as these expenses are passed through to our customers and, consequently, we do not realize any gain or loss on transportation revenues. Segment Adjusted EBITDA Expense is used as a supplemental financial measure by our management to assess the operating performance of our segments. Segment Adjusted EBITDA Expense is a key component of Segment Adjusted EBITDA in addition to coal sales, royalty revenues and other revenues. The exclusion of corporate general and administrative expenses from Segment Adjusted EBITDA Expense allows management to focus solely on the evaluation of segment operating performance as it primarily relates to our operating expenses. We also review Segment Adjusted EBITDA Expense on a per ton basis for cost trends at our coal operations by dividing Segment Adjusted EBITDA expense by coal sales volumes.

Segment Adjusted EBITDA

We define Segment Adjusted EBITDA (a non-GAAP financial measure) as net income attributable to ARLP before net interest expense, income taxes, depreciation, depletion and amortization and general and administrative expenses adjusted for certain items that we characterize as unrepresentative of our ongoing operations. Segment Adjusted EBITDA is a key component of consolidated Adjusted EBITDA, which is used as a supplemental financial measure by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others. We believe that the presentation of consolidated Adjusted EBITDA provides useful information to investors

regarding our performance and results of operations because Adjusted EBITDA, when used in conjunction with related GAAP financial measures, (i) provides additional information about our core operating performance and ability to generate and distribute cash flow, (ii) provides investors with the financial analytical framework upon which we base financial, operational, compensation and planning decisions and (iii) presents a measurement that investors, rating agencies and debt holders have indicated is useful in assessing us and our results of operations.

Segment Adjusted EBITDA is also used as a supplemental measure by our management for reasons similar to those stated in the previous explanation of Adjusted EBITDA. In addition, the exclusion of corporate general and administrative expenses from Segment Adjusted EBITDA allows management to focus solely on the evaluation of segment operating profitability as it relates to our revenues and operating expenses, which are primarily controlled by our segments.

Analysis of Historical Results of Operations – 2025 Compared with 2024

Consolidated Information

	Year Ended December 31,		Increase (Decrease)	
	2025	2024		
	(in thousands)			
Consolidated Total				
Tons sold	32,967	33,319	(352)	(1.1)%
Tons produced	33,167	32,206	961	3.0 %
Volume - BOE (1)	3,648	3,402	246	7.2 %
Coal sales	\$ 1,932,515	\$ 2,111,803	\$ (179,288)	(8.5)%
Oil & gas royalties	\$ 137,849	\$ 138,311	\$ (462)	(0.3)%
Total revenues	\$ 2,194,811	\$ 2,448,708	\$ (253,897)	(10.4)%
Segment Adjusted EBITDA Expense (2)	\$ 1,391,230	\$ 1,530,001	\$ (138,771)	(9.1)%
Net income of ARLP	\$ 311,163	\$ 360,855	\$ (49,692)	(13.8)%
Segment Adjusted EBITDA (2)	\$ 781,858	\$ 796,454	\$ (14,596)	(1.8)%

(1) BOE for natural gas is calculated on a 6:1 basis (6,000 cubic feet of natural gas to one barrel).

(2) For definitions of Segment Adjusted EBITDA and Segment Adjusted EBITDA Expense and related reconciliations to their respective comparable GAAP financial measures, please see below under “— Reconciliation of Non-GAAP Financial Measures.”

Total Revenues

Total revenues decreased 10.4% to \$2.19 billion in 2025 compared to \$2.45 billion 2024 primarily due to lower coal sales pricing and transportation revenues.

- Coal sales decreased to \$1.93 billion in 2025 compared to \$2.11 billion in 2024. The decrease was attributable to lower average coal sales prices, which reduced coal sales by \$157.0 million and lower tons sold, which reduced coal sales by \$22.3 million. Coal sales prices decreased by 7.5% as a result of lower domestic price realizations at several mines due to the continued roll-off of higher-priced contracts entered into during the energy crisis and reduced export price realizations from our MC Mining and Mettiki mines.
- Transportation revenues and expenses were \$36.6 million and \$112.6 million in 2025 and 2024, respectively. The decrease of \$76.0 million was primarily attributable to lower third-party transportation rates in 2025 and decreased coal shipments to the international markets for which we arrange third-party transportation. Transportation revenues are recognized when title to the coal passes to the customer and recognized in an amount equal to the corresponding transportation expenses.

Segment Adjusted EBITDA Expense

Segment Adjusted EBITDA Expense decreased 9.1% to \$1.39 billion in 2025 primarily related to our coal operations which decreased 9.3% to \$1.36 billion, as a result of lower per ton costs and sales volumes. Segment Adjusted EBITDA Expense per ton sold for our coal operations decreased 8.4% to \$41.29 per ton sold in 2025 compared to \$45.07 per ton in 2024, primarily due to an increased sales mix of tons from lower cost operations, higher recoveries from several mines and fewer longwall move days at our Hamilton operation as well as the following per ton cost decreases:

- Labor and benefit expenses, excluding workers' compensation, per ton produced decreased 6.8% to \$13.06 per ton in 2025 from \$14.01 per ton in 2024. The decrease of \$0.95 per ton was primarily due to lower direct labor costs at several mines.
- Material and supplies expenses per ton produced decreased 12.2% to \$13.95 per ton in 2025 from \$15.88 per ton in 2024. The decrease of \$1.93 per ton produced primarily reflects decreases of \$0.67 per ton for roof support, \$0.33 per ton in longwall subsidence expense, and \$0.28 per ton for contract labor used in the mining process.
- Maintenance expenses per ton produced decreased 13.1% to \$4.70 per ton in 2025 from \$5.41 per ton in 2024. The decrease of \$0.71 per ton produced was primarily a result of lower maintenance costs at several mines.
- Outside coal purchases decreased to \$21.8 million in 2025 compared to \$35.8 million in 2024. The decrease in outside coal purchases benefited costs per ton in 2025 since the cost of outside coal purchases is generally higher on a per ton basis than our produced coal.

Depreciation, depletion and amortization

Depreciation, depletion and amortization expense increased to \$299.4 million in 2025 compared to \$285.4 million in 2024 primarily as a result of recent capital investments at our River View and Tunnel Ridge mines.

Asset impairments

During 2024, we recorded \$31.1 million of non-cash asset impairment charges as a result of our decision to reduce production at our MC Mining operation due to market uncertainty, challenging geology and higher costs. Please read "Item 8. Financial Statements and Supplementary Data—Note 9 – Long-Lived Asset Impairments" for more information.

Equity method investment income (loss)

We had equity method investment income of \$21.0 million in 2025 compared to an equity method investment loss of \$5.0 million in 2024. The change was primarily due to income attributable to our investments in Gavin Generation and NGP ET IV.

Change in fair value of digital assets

We recorded a \$4.4 million decrease in the fair value of our digital assets in 2025 compared to an increase of \$22.4 million during 2024 reflecting the movement in the price of bitcoin during each period.

Impairment loss on investments

During 2025, we recorded impairments totaling \$28.0 million on our equity and debt investments in Ascend. Please read "Item 8. Financial Statements and Supplementary Data—Note 10 – Investments" for more information.

Net income attributable to ARLP

Net income attributable to ARLP for 2025 was \$311.2 million, or \$2.40 per basic and diluted limited partner unit, compared to \$360.9 million, or \$2.77 per basic and diluted limited partner unit, for 2024 as a result of lower revenues and

a decrease in the fair value of our digital assets in 2025, partially offset by reduced operating expenses and increased investment income.

Segment Adjusted EBITDA

Our 2025 Segment Adjusted EBITDA decreased \$14.6 million, or 1.8%, to \$781.9 million from 2024 Segment Adjusted EBITDA of \$796.5 million.

Segment Information

	Year Ended December 31,			
	2025	2024	Increase (Decrease)	
	(in thousands)			
Illinois Basin Coal Operations				
Tons sold	25,769	24,787	982	4.0 %
Coal sales	\$ 1,342,334	\$ 1,399,100	\$ (56,766)	(4.1)%
Other revenues	\$ 8,861	\$ 11,901	\$ (3,040)	(25.5)%
Segment Adjusted EBITDA Expense	\$ 894,521	\$ 937,083	\$ (42,562)	(4.5)%
Segment Adjusted EBITDA	\$ 456,674	\$ 473,918	\$ (17,244)	(3.6)%
Appalachia Coal Operations				
Tons sold	7,198	8,532	(1,334)	(15.6)%
Coal sales	\$ 590,181	\$ 712,703	\$ (122,522)	(17.2)%
Other revenues	\$ 2,877	\$ 3,091	\$ (214)	(6.9)%
Segment Adjusted EBITDA Expense	\$ 459,351	\$ 551,734	\$ (92,383)	(16.7)%
Segment Adjusted EBITDA	\$ 133,707	\$ 164,060	\$ (30,353)	(18.5)%
Oil & Gas Royalties				
Volume - BOE (1)	3,648	3,402	246	7.2 %
Oil & gas royalties	\$ 137,849	\$ 138,311	\$ (462)	(0.3)%
Other revenues	\$ 1,707	\$ 825	\$ 882	106.9 %
Segment Adjusted EBITDA Expense	\$ 18,447	\$ 19,853	\$ (1,406)	(7.1)%
Segment Adjusted EBITDA	\$ 117,528	\$ 116,958	\$ 570	0.5 %
Coal Royalties				
Volume - Tons sold (2)	24,120	21,085	3,035	14.4 %
Intercompany coal royalties	\$ 80,471	\$ 69,676	\$ 10,795	15.5 %
Segment Adjusted EBITDA Expense	\$ 27,612	\$ 25,759	\$ 1,853	7.2 %
Segment Adjusted EBITDA	\$ 52,859	\$ 43,982	\$ 8,877	20.2 %

(1) BOE for natural gas is calculated on a 6:1 basis (6,000 cubic feet of natural gas to one barrel).

(2) Represents tons sold by our coal operations segments associated with coal reserves leased from our Coal Royalties Segment.

Illinois Basin Coal Operations – Segment Adjusted EBITDA decreased 3.6% to \$456.7 million in 2025 from \$473.9 million in 2024. The decrease of \$17.2 million was primarily attributable to lower coal sales prices, partially offset by higher sales volumes and lower operating expenses. Coal sales price per ton decreased by 7.7% compared to 2024 as a result of lower domestic price realizations across the region. Sales volumes increased by 4.0% compared to 2024 due primarily to increased tons sold from our Hamilton and River View mines. Segment Adjusted EBITDA Expense decreased 4.5% compared to 2024 due to lower operating expenses per ton. Segment Adjusted EBITDA Expense per ton in 2025 decreased by 8.2% compared to 2024 due primarily to increased production and improved recoveries at our River View and Hamilton mines, higher volumes at our Warrior operation, and reduced longwall move days at Hamilton.

Appalachia Coal Operations – Segment Adjusted EBITDA decreased 18.5% to \$133.7 million in 2025 from \$164.1 million in 2024. The decrease of \$30.4 million was primarily attributable to lower coal sales, which decreased 17.2% to \$590.2 million in 2025 from \$712.7 million in 2024, partially offset by lower operating expenses. The decrease in coal sales reflects lower coal sales volumes and price realizations. Tons sold decreased by 15.6% in 2025 compared to 2024 primarily as a result of lower production levels at Tunnel Ridge due to challenging mining conditions and the recent

transition to a new longwall district. Average coal sales price per ton decreased by 1.8% compared to 2024 primarily due to reduced domestic pricing from our Tunnel Ridge and MC Mining operations and lower export price realizations from MC Mining and Mettiki, partially offset by a greater mix of higher priced sales tons from the MC Mining and Mettiki operations during 2025. Segment Adjusted EBITDA Expense decreased 16.7% to \$459.4 million in 2025 from \$551.7 million in 2024 due to reduced volumes and lower per ton operating expenses. Segment Adjusted EBITDA Expense per ton for 2025 decreased by 1.3% compared to 2024 due to higher recoveries at the Mettiki and MC Mining operations.

Oil & Gas Royalties – Segment Adjusted EBITDA increased slightly to \$117.5 million for 2025 from \$117.0 million in 2024. The increase was primarily due to increased volumes in 2025, which increased by 7.2%, higher other revenues and lower expenses, partially offset by lower average sales price per BOE, which decreased 7.0% to \$37.79 per BOE. Higher BOE volumes during 2025 resulted from increased drilling and completion activities on our properties and additional volumes from oil & gas mineral interest acquisitions.

Coal Royalties – Segment Adjusted EBITDA increased 20.2% to \$52.9 million for 2025 from \$44.0 million in 2024. The \$8.9 million increase was a result of increased royalty tons sold and higher average royalty rates per ton.

Analysis of Historical Results of Operations – 2024 Compared with 2023

For discussion and analysis of 2024 compared to 2023, please refer to “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” of our Annual Report on Form 10-K for the year ended December 31, 2024, which was filed with the SEC on February 27, 2025, and is incorporated by reference herein.

Reconciliation of Non-GAAP Financial Measures

The following is a reconciliation of net income, the most comparable GAAP financial measure, to consolidated Segment Adjusted EBITDA:

	Year Ended December 31,	
	2025	2024
	(in thousands)	
Net income	\$ 317,250	\$ 365,557
Noncontrolling interest	(6,087)	(4,702)
Net income attributable to ARLP	\$ 311,163	\$ 360,855
General and administrative	83,119	82,224
Depreciation, depletion and amortization	299,436	285,446
Asset impairments	—	31,130
Interest expense, net	36,984	28,007
Change in fair value of digital assets	4,354	(22,395)
Impairment loss on investments	28,037	—
Litigation expense accrual	—	15,250
Income tax expense	18,765	15,937
Consolidated Segment Adjusted EBITDA	<u>\$ 781,858</u>	<u>\$ 796,454</u>

The following is a reconciliation of operating expenses, the most comparable GAAP financial measure, to consolidated Segment Adjusted EBITDA Expense:

	Year Ended December 31,	
	2025	2024
	(in thousands)	
Operating expenses (excluding depreciation, depletion and amortization)	\$ 1,368,521	\$ 1,507,398
Litigation expense accrual	—	(15,250)
Outside coal purchases	21,820	35,791
Other expense	889	2,062
Consolidated Segment Adjusted EBITDA Expense	<u>\$ 1,391,230</u>	<u>\$ 1,530,001</u>

Liquidity and Capital Resources

Liquidity

We have historically satisfied our working capital requirements and funded our capital expenditures, investments, contractual obligations and debt service obligations with cash generated from operations, cash provided by the issuance of debt or equity, borrowings under credit and securitization facilities and other financing transactions. We believe that existing cash balances, consisting of cash and cash equivalents of \$71.2 million at December 31, 2025, future cash flows from operations and investments, borrowings under credit facilities and cash provided from the issuance of debt or equity will be sufficient to meet our working capital requirements, capital expenditures and additional investments, debt payments, contractual obligations, commitments and distribution payments. Nevertheless, our ability to satisfy our working capital requirements and additional investments, to satisfy our contractual obligations, to fund planned capital expenditures, to service our debt obligations or to pay distributions will depend upon our future operating performance and access to and cost of financing sources, which will be affected by prevailing economic conditions generally, and in both the coal and oil & gas industries specifically, as well as other financial and business factors, some of which are beyond our control. Based on our recent operating cash flow results, current cash position, anticipated future cash flows and sources of financing that we expect to have available, we anticipate being in compliance with the covenants of the Credit Agreement and expect to have sufficient liquidity to fund our operations and growth strategies. However, to the extent operating cash flow or access to and cost of financing sources are materially different than expected, future covenant compliance or liquidity may be adversely affected. Please see “Item 1A. Risk Factors.”

Unit Repurchase Program

We have \$80.6 million remaining authorized under our unit repurchase program as of December 31, 2025. No units were repurchased during the year ended December 31, 2025. The program has no time limit and we may repurchase units from time to time in the open market or in other privately negotiated transactions. The unit repurchase program authorization does not obligate us to repurchase any dollar amount or number of units, and repurchases may be commenced or suspended from time to time without prior notice. The timing of any future unit repurchases and the ultimate number of units to be purchased will depend on several factors, including business and market conditions, our future financial performance, and other capital priorities. Please read “Item 5. Market for Registrant’s Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities” for more information on the unit repurchase program.

Securitization Facility

In January 2026, we extended the term of our \$75.0 million Securitization Facility to January 2027. For additional information on the Securitization Facility please read “Item 8. Financial Statements and Supplementary Data—Note 12 – Long-Term Debt”.

Cash Flows

Cash provided by operating activities was \$651.1 million for 2025 compared to \$803.1 million for 2024. The decrease in cash provided by operating activities was primarily due to the decrease in net income adjusted for non-cash items and unfavorable working capital changes primarily related to trade receivables and other miscellaneous changes. These decreases were partially offset by favorable working capital changes primarily related to accounts payable, other receivables, and accrued payroll and related benefits.

Net cash used in investing activities was \$331.3 million for 2025 compared to \$440.7 million for 2024. The decrease in cash used in investing activities was primarily due to the decrease in capital expenditures and a decrease in oil & gas reserve acquisitions in 2025 as compared to 2024. This decrease was partially offset by increased contributions to equity method investments, changes in accounts payable and accrued liabilities and the purchase of equity securities during 2025.

Net cash used in financing activities was \$385.7 million for 2025 compared to \$285.3 million for 2024. The increase in cash used in financing activities was primarily attributable to proceeds from the issuance of our 2029 Senior Notes and from an equipment financing in 2024. These increases were partially offset by reduced payments on long-term debt, reduced distributions paid to partners in 2025 and the payment for cash settlement of grants under deferred compensation plans in 2024.

Capital Expenditures

For 2026, we are targeting total capital expenditures between \$280 million and \$300 million. We project average estimated annual maintenance capital expenditures over the next five years of approximately \$7.23 per ton produced.

Other Cash Requirements

We expect to incur significant future cash outflows for scheduled payments on long-term debt, lease obligations, asset retirement obligation costs and workers' compensation and pneumoconiosis as follows:

Year Ended December 31,	(in thousands)
2026	\$ 49,663
2027	49,585
2028	21,447
2029	418,249
2030	12,785
Thereafter	543,491
	<u>\$ 1,095,220</u>

For additional information on our future cash requirements other than capital expenditures, please see "Item 8. Financial Statements and Supplementary Data—Note 12 – Long-Term Debt," "—Note 11 – Leases," "—Note 14 – Employee Benefit Plans," "—Note 15 – Asset Retirement Obligations," and "—Note 13 – Accrued Workers' Compensation and Pneumoconiosis Benefits"

In addition to the cash outflows discussed above, we have liabilities totaling \$164.9 million expected to be paid in 2026 and \$55.6 million in years thereafter. Our liabilities include accounts payable, accrued expenses, contingent consideration and other miscellaneous liabilities which include amounts payable for subsidence and deferred income taxes. We also have contractual commitments of \$94.3 million as of December 31, 2025, that we expect to pay during 2026. Please see "Item 8. Financial Statements and Supplementary Data—Note 16 – Commitments and Contingencies."

Off-Balance-Sheet Arrangements

We use a combination of surety bonds and letters of credit to secure our financial obligations for reclamation, workers' compensation and other obligations as follows as of December 31, 2025:

	Reclamation Obligation	Workers' Compensation Obligation	Other	Total
		(in millions)		
Surety bonds	\$ 158.0	\$ 66.0	\$ 13.8	\$ 237.8
Letters of credit	—	38.5	19.2	57.7

Insurance

Effective October 1, 2025, we renewed our property and casualty insurance program through September 30, 2026. Our property insurance was procured from our wholly owned captive insurance company, Wildcat Insurance. Wildcat Insurance charged certain of our subsidiaries for the premiums on this program and in return purchased reinsurance for the program in the standard market. The maximum limit in the commercial property program is \$100.0 million per occurrence, excluding a \$1.5 million deductible for property damage, a 75- or 90-day waiting period for underground business interruption depending on the mining complex and an additional \$25.0 million overall aggregate deductible. We retained a 2.50% participating interest in our current commercial property insurance program. We can make no assurances that we will not experience significant insurance claims in the future that could have a material adverse effect on our business, financial condition, results of operations and ability to purchase property insurance in the future. Also, exposures exist for which no insurance may be available and for which we have not reserved. In addition, the insurance industry has been subject to efforts by environmental activists to restrict coverages available for fossil-fuel companies.

Debt Obligations

See “Item 8. Financial Statements and Supplementary Data—Note 12 – Long-Term Debt” for a discussion of our debt obligations.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition, results of operations, liquidity and capital resources is based on our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts and disclosures in the consolidated financial statements. We base our estimates on historical experience and on various other assumptions that we believe are reasonable under the circumstances. We discuss these estimates and judgments with the Audit Committee periodically. Actual results may differ from these estimates. We have provided a description of all significant accounting policies in the notes to our consolidated financial statements. The following critical accounting policies are materially impacted by judgments, assumptions and estimates used in the preparation of our consolidated financial statements:

Business Combinations

We account for business acquisitions using the purchase method of accounting. See “Item 8. Financial Statements and Supplementary Data—Note 4 – Acquisitions” for more information on the Skyland and Elk Range Acquisitions. Assets acquired and liabilities assumed are recorded at their estimated fair values at the acquisition date. The excess purchase price over the fair value of net assets acquired, if any, is recorded as goodwill. Given the time it takes to obtain pertinent information to finalize the acquired business’ balance sheet, it may be several quarters before we are able to finalize those initial fair value estimates. Accordingly, it is not uncommon for the initial estimates to be subsequently revised. The results of operations of acquired businesses are included in the consolidated financial statements from the acquisition date.

For the Skyland and Elk Range Acquisitions, we determined a fair value for the acquired mineral interests using an income approach consisting of discounted cash flow models. The assumptions used in the discounted cash flow models included estimated production, projected cash flows, forward oil & gas prices and risk adjusted discount rates.

Oil & Gas Reserve Values

Estimated oil & gas reserves and estimated market prices for oil & gas are a significant part of our depletion calculations, impairment analyses, and other estimates. Following are examples of how these estimates affect financial results:

- an increase (decrease) in estimated proved oil & gas reserves can reduce (increase) our units of production depreciation, depletion and amortization rates; and
- changes in oil & gas reserves and estimated market prices both impact projected future cash flows from our mineral interests. This in turn can impact our periodic impairment analysis.

The process of estimating oil & gas reserves is very complex, requiring significant judgment in the evaluation of all available geological, geophysical, engineering and economic data. After being estimated internally, our proved reserves estimates are compared to proved reserves that are audited by independent experts in connection with our required year-end reporting. The data may change substantially over time as a result of numerous factors, including the historical 12 month average price, additional development cost and activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates could occur from time to time. Such changes could trigger an impairment of our oil & gas mineral interests and have an impact on our depreciation, depletion and amortization expense prospectively.

Estimates of future commodity prices utilized in our impairment analyses consider market information including published forward oil & gas prices. The forecasted price information used in our impairment analyses is consistent with that generally used in evaluating third-party operator drilling decisions and our expected acquisition plans, if any. Prices for future periods will impact the production economics underlying oil & gas reserve estimates. In addition, changes in the price of oil & gas also impact certain costs associated with our expected underlying production and future capital costs. The prices of oil & gas are volatile and change from period to period, thus are expected to impact our estimates. Significant

unfavorable changes in the estimated future commodity prices could result in an impairment of our oil & gas mineral interests.

Workers' Compensation and Pneumoconiosis (Black Lung) Benefits

We provide income replacement and medical treatment for work-related traumatic injury claims as required by applicable state laws. We generally provide for these claims through self-insurance programs. Workers' compensation laws also compensate survivors of workers who suffer employment related deaths. Our liability for traumatic injury claims is the estimated present value of current workers' compensation benefits, based on our actuary estimates. Our actuarial calculations are based on a blend of actuarial projection methods and numerous assumptions including claim development patterns, mortality, medical costs and interest rates. See "Item 8. Financial Statements and Supplementary Data—Note 13 – Accrued Workers' Compensation and Pneumoconiosis Benefits" for additional discussion. We had accrued liabilities for workers' compensation of \$49.4 million and \$47.9 million for these costs at December 31, 2025 and 2024, respectively. A one-percentage-point reduction in the discount rate would have increased operating expense by approximately \$2.1 million for the year ended December 31, 2025. We limit our exposure to traumatic injury claims by purchasing a high deductible insurance policy that starts paying benefits after deductibles for a particular claim year have been met. Our receivables for traumatic injury claims under this policy as of December 31, 2025 and 2024 were \$4.1 million and \$3.7 million, respectively.

Coal mining companies are subject to FMSHA and various state statutes for the payment of medical and disability benefits to eligible recipients related to coal worker's pneumoconiosis, or black lung. We provide for these claims through self-insurance programs. Our pneumoconiosis benefits liability is calculated using the service cost method based on the actuarial present value of the estimated pneumoconiosis benefits obligation. Our actuarial calculations are based on numerous assumptions including disability incidence, medical costs, mortality, death benefits, dependents and discount rates. We had accrued liabilities of \$105.0 million and \$124.3 million for the pneumoconiosis benefits at December 31, 2025 and 2024, respectively. A one-percentage-point reduction in the discount rate would have increased the expense recognized for the year ended December 31, 2025 by approximately \$0.8 million. Under the service cost method used to estimate our pneumoconiosis benefits liability, actuarial gains or losses attributable to changes in actuarial assumptions, such as the discount rate, are amortized over the remaining service period of active miners.

The discount rate for workers' compensation and pneumoconiosis is derived by applying the Financial Times Stock Exchange Pension Discount Curve to the projected liability payout. Other assumptions, such as claim development patterns, mortality, disability incidence and medical costs, are based on standard actuarial tables adjusted for our actual historical experiences whenever possible. We review all actuarial assumptions periodically for reasonableness and consistency and update such factors when underlying assumptions, such as discount rates, change or when sustained changes in our historical experiences indicate a shift in our trend assumptions are warranted.

Impairment of Long-Lived Assets

In addition to oil & gas reserves discussed above in the *Oil & Gas Reserve Values* section, we review the carrying value of long-lived assets and certain identifiable intangibles whenever events or changes in circumstances indicate that the carrying amount may not be recoverable based on estimated undiscounted future cash flows. Long-lived assets and certain intangibles are not reviewed for impairment unless an impairment indicator is noted. Several examples of impairment indicators include:

- A significant decrease in the market price of a long-lived asset;
- A significant adverse change in the extent or manner in which a long-lived asset is being used or in its physical condition;
- A significant adverse change in legal factors or in the business climate that could affect the value of a long-lived asset, including an adverse action of assessment by a regulator;
- An accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset;
- A current-period operating or cash flow loss combined with a history of operating or cash flow losses or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset; or
- A current expectation that, more likely than not, a long-lived asset will be sold or otherwise disposed of significantly before the end of its previously estimated useful life. The term more likely than not refers to a level of likelihood that is more than 50 percent.

The above factors are not all inclusive, and management must continually evaluate whether other factors are present that would indicate a long-lived asset may be impaired. If there is an indication that the carrying amount of an asset group may not be recovered, we compare our estimate of undiscounted future cash flows attributable to the asset to the carrying value of the asset group. Individual assets are grouped for impairment review purposes based on the lowest level for which there is identifiable cash flows that are largely independent of the cash flows of other groups of assets, generally on a by-mine basis. Assumptions about sales, operating margins, capital expenditures and sales prices are based on our budgets, business plans, economic projections, and anticipated future cash flows. If the carrying value of an asset group exceeds the future undiscounted cash flows expected from the asset group, the amount of impairment is measured by the difference between the carrying value and the fair value of the asset group. The fair value of impaired assets is typically determined based on various factors, including cost replacement, the present values of expected future cash flows using a risk adjusted discount rate, the marketability of the assets and the estimated fair value of assets that could be sold or used at other operations. We recorded an asset impairment of \$31.1 million in 2024. See “Item 8. Financial Statements and Supplementary Data—Note 9 – Long-Lived Asset Impairments”.

Asset Retirement Obligations

SMCRA and similar state statutes require that mined property be restored in accordance with specified standards and an approved reclamation plan. A liability is recorded for the estimated cost of future mine asset retirement and closing procedures on a present value basis when incurred or acquired and a corresponding amount is capitalized by increasing the carrying amount of the related long-lived asset. Those costs relate to permanently sealing portals at underground mines and to reclaiming the final pits and support surface acreage for both our underground mines and past surface mines. Examples of these types of costs, common to both types of mining, include, but are not limited to, removing or covering refuse piles and settling ponds, water treatment obligations, and dismantling preparation plants, other facilities and roadway infrastructure. Accrued liabilities of \$157.6 million and \$158.8 million for these costs are recorded at December 31, 2025 and 2024, respectively. See “Item 8. Financial Statements and Supplementary Data—Note 15 – Asset Retirement Obligations” for additional information. The liability for asset retirement and closing procedures is sensitive to changes in cost estimates, estimated mine lives and timing of post-mine reclamation activities. As changes in estimates occur (such as mine plan revisions, changes in estimated costs or changes in timing of the performance of reclamation activities), the revisions to the obligation and asset are recognized at the appropriate credit-adjusted, risk-free interest rate.

Accounting for asset retirement obligations also requires depreciation of the capitalized asset retirement cost and accretion of the asset retirement obligation over time. Depreciation is generally determined on a units-of-production basis and accretion is generally recognized over the life of the producing assets.

On at least an annual basis, we review our entire asset retirement obligation liability and make necessary adjustments for permit changes approved by state authorities, changes in the timing of reclamation activities, and revisions to cost estimates and productivity assumptions, to reflect current experience. Adjustments to the liability associated with these assumptions resulted in a decrease of \$4.2 million for the year ended December 31, 2025. Adjustments to the liability associated with these assumptions resulted in an increase of \$5.6 million for the year ended December 31, 2024.

While the precise amount of these future costs cannot be determined with certainty, we have estimated the costs and timing of future asset retirement obligations escalated for inflation, then discounted and recorded at the present value of those estimates. Discounting resulted in reducing the accrual for asset retirement obligations by \$112.3 million and \$120.1 million at December 31, 2025 and 2024, respectively. We estimate that the aggregate undiscounted cost of final mine closure is approximately \$269.9 million and \$278.9 million at December 31, 2025 and 2024, respectively. If our assumptions differ from actual experiences, or if changes in the regulatory environment occur, our actual cash expenditures and costs that we incur could be materially different than currently estimated.

Related-Party Transactions

See “Item 8. Financial Statements and Supplementary Data—Note 21 – Related-Party Transactions” and “Item 13. Certain Relationship and Related Transactions, and Director Independence” for a discussion of our related-party transactions.

New Accounting Standards

See “Item 8. Financial Statements and Supplementary Data—Note 2 – Summary of Significant Accounting Policies” for a discussion of new accounting standards.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

We have significant long-term sales contracts as evidenced by approximately 84.6% of our sales tonnage being sold under long-term sales contracts in 2025. Many of the long-term sales contracts are subject to price adjustment provisions, which periodically permit an increase or decrease in the contract price, typically to reflect changes in specified indices or changes in production costs resulting from regulatory changes, or both. For additional discussion of coal supply agreements, please see “Item 1. Business—Coal Marketing and Sales” and “Item 8. Financial Statements and Supplementary Data—Note 20 – Concentration of Credit Risk and Major Customers.”

Our results of operations are highly dependent upon the prices we receive for our coal, oil and natural gas. Regarding coal, the short-term sales contracts favored by some of our coal customers leave us more exposed to risks of declining coal price periods. Also, a significant decline in oil & gas prices would have a significant impact on our oil & gas royalty revenues.

We have exposure to coal and oil & gas sales prices and price risk for supplies that are used directly or indirectly in the normal course of coal and oil & gas production such as electricity, steel and other supplies. We manage our risk for these items through strategic sourcing contracts for normal quantities required by our operations. Historically, we have not utilized any commodity price-hedges or other derivatives related to either our sales price or supply cost risks but may do so in the future.

Credit Risk

In 2025, approximately 89.2% of our tons sold were purchased by U.S. electric utilities and 8.6% were sold into the international markets through brokered transactions. Therefore, our credit risk is primarily with domestic electric power generators and reputable global brokerage firms. Our policy is to independently evaluate each customer’s creditworthiness prior to entering into transactions and to constantly monitor outstanding accounts receivable. When deemed appropriate by our credit management department, we will take steps to reduce our credit exposure to customers that do not meet our credit standards or whose credit has deteriorated. These steps may include obtaining letters of credit or cash collateral, requiring prepayments for shipments or establishing customer trust accounts held for our benefit in the event of a failure to pay. Such credit risks from customers may impact the borrowing capacity of our Securitization Facility. See “Item 8. Financial Statements and Supplementary Data—Note 12 – Long-Term Debt” for more information on our Securitization Facility.

Exchange Rate Risk

The majority of our transactions are denominated in United States dollars, and as a result, we do not have material exposure to currency exchange-rate risks. However, because we periodically sell our coal internationally in United States dollars, general economic conditions in foreign markets and changes in foreign currency exchange rates may provide our foreign competitors with a competitive advantage. If our competitors’ currencies decline against the United States dollar or against foreign purchasers’ local currencies, those competitors may be able to offer lower prices for coal to these purchasers. Furthermore, if the currencies of overseas purchasers were to significantly decline in value in comparison to the United States dollar, those purchasers may seek decreased prices for the coal we sell to them. Consequently, currency fluctuations could adversely affect the competitiveness of our coal in international markets.

Interest Rate Risk

Borrowings under the Revolving Credit Facility, Term Loan and Securitization Facility are at variable rates and, as a result, we have interest rate exposure. Historically, our earnings have not been materially affected by changes in interest rates and we have not utilized interest rate derivative instruments related to our outstanding debt. We had \$31.6 million in borrowings under Term Loan at December 31, 2025. We did not have any outstanding borrowings on either the Revolving Credit Facility or the Securitization Facility at December 31, 2025. A one percentage point increase in the interest rates related to the Term Loan would result in an annualized increase in interest expense of \$0.3 million, based on borrowing levels at December 31, 2025. With respect to our fixed-rate borrowings, we had \$400.0 million in borrowings under our 2029 Senior Notes and \$31.8 million in borrowings under our equipment financings at December 31, 2025. A one

percentage point increase in interest rates would result in a decrease of approximately \$13.3 million in the estimated fair value of these borrowings.

The table below provides information about our market sensitive financial instruments and constitutes a “forward-looking statement.” The fair values of long-term debt are estimated using discounted cash flow analyses, based on our incremental borrowing rates for similar types of borrowing arrangements as of December 31, 2025 and 2024.

The carrying amounts and fair values of financial instruments are as follows:

Expected Maturity Dates as of December 31, 2025	2026	2027	2028	2029	2030	Total	Fair Value December 31, 2025
(dollars in thousands)							
Fixed rate debt	\$ 13,978	\$ 15,182	\$ 2,655	\$ 400,000	\$ —	\$ 431,815	\$ 477,203
Weighted-average interest rate	8.61 %	8.62 %	8.62 %	8.63 %	— %		
Variable rate debt	\$ 14,063	\$ 14,063	\$ 3,515	\$ —	\$ —	\$ 31,641	\$ 31,641
Weighted-average interest rate (1)	7.71 %	7.71 %	7.71 %	— %	— %		

Expected Maturity Dates as of December 31, 2024	2025	2026	2027	2028	2029	Total	Fair Value December 31, 2024
(dollars in thousands)							
Fixed rate debt	\$ 12,607	\$ 14,240	\$ 15,182	\$ 2,655	\$ 400,000	\$ 444,684	\$ 477,757
Weighted-average interest rate	8.60 %	8.61 %	8.62 %	8.62 %	8.63 %		
Variable rate debt	\$ 14,062	\$ 14,063	\$ 14,063	\$ 3,515	\$ —	\$ 45,703	\$ 45,703
Weighted-average interest rate (1)	7.71 %	7.71 %	7.71 %	7.71 %	— %		

(1) Interest rate of variable rate debt equal to the rate effective at December 31, 2025 and 2024, held constant for the remaining term of the outstanding borrowing.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

	Page
Report of Independent Registered Public Accounting Firm (PCAOB ID Number 248)	96
Consolidated Balance Sheets	98
Consolidated Statements of Income	99
Consolidated Statements of Comprehensive Income	100
Consolidated Statements of Cash Flows	101
Consolidated Statement of Partners' Capital	102
Notes to Consolidated Financial Statements	103
1. Organization and Presentation	103
2. Summary of Significant Accounting Policies	104
3. Variable Interest Entities	113
4. Acquisitions	114
5. Fair Value Measurements	116
6. Inventories	118
7. Digital Assets	118
8. Property, Plant and Equipment	119
9. Long-Lived Asset Impairments	120
10. Investments	120
11. Leases	122
12. Long-Term Debt	123
13. Accrued Workers' Compensation and Pneumoconiosis Benefits	126
14. Employee Benefit Plans	128
15. Asset Retirement Obligations	132
16. Commitments and Contingencies	133
17. Partners' Capital	133
18. Common Unit-Based Compensation Plans	134
19. Revenue From Contracts With Customers	136
20. Concentration of Credit Risk and Major Customers	137
21. Related-Party Transactions	137
22. Income Taxes	139
23. Earnings Per Limited Partner Unit	141
24. Supplemental Cash Flow Information	142
25. Segment Information	142
26. Subsequent Event	145
Supplemental Oil & Gas Reserve Information (Unaudited)	146
Schedule I – Condensed Financial Information of Registrant	152

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors of Alliance Resource Management GP, LLC
and Unitholders of Alliance Resource Partners, L.P.

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Alliance Resource Partners, L.P. (a Delaware limited partnership) and subsidiaries (the “Partnership”) as of December 31, 2025 and 2024, the related consolidated statements of income, comprehensive income, cash flows and partners’ capital for each of the three years in the period ended December 31, 2025, and the related notes and financial statement schedule included under Item 15(a)(2) (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 Partnership 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.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (“PCAOB”), the Partnership’s internal control over financial reporting as of December 31, 2025, based on criteria established in the 2013 Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”), and our report dated February 26, 2026 expressed an unqualified opinion.

Basis for opinion

These consolidated financial statements are the responsibility of the Partnership’s management. Our responsibility is to express an opinion on the Partnership’s consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical audit matter

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

Valuation of workers’ compensation and pneumoconiosis benefit obligations

As described further in Note 13 to the consolidated financial statements, the Partnership provides income replacement and medical treatment for work-related traumatic injury claims and compensation to survivors of workers who suffer employment-related deaths. The Partnership is also liable to pay benefits for black lung disease (or pneumoconiosis) to eligible employees and former employees and their dependents. As of December 31, 2025, the Partnership’s aggregate workers’ compensation and pneumoconiosis benefit obligations were approximately \$154 million. We identified valuation of workers’ compensation and pneumoconiosis benefit obligations as a critical audit matter.

The principal considerations for our determination that the valuation of workers’ compensation and pneumoconiosis benefit obligations is a critical audit matter are the high level of estimation uncertainty related to determining the frequency and severity of these types of claims, as well as the inherent subjectivity in management’s judgment in estimating eligible benefits and the total cost to settle or dispose of these claims. Workers’ compensation and pneumoconiosis benefit

obligations are determined using actuarial projection methods and numerous assumptions including claim development patterns, costs, and mortality. The estimates rely on the assumption that historical claim patterns are an accurate representation for future claims.

Our audit procedures related to the valuation of workers' compensation and pneumoconiosis benefit obligations included the following, among others.

- We tested the design and operating effectiveness of controls relating to the workers' compensation and pneumoconiosis benefit obligations process including testing controls over management's review of actuarial specialists' liability calculations and the completeness and accuracy of the underlying data.
- We tested management's process for determining the worker's compensation and pneumoconiosis benefit obligation accruals, including evaluating the reasonableness of the methods and significant assumptions used in the calculations with the assistance of actuarial specialists.
- We tested the claims data used in the actuarial calculations by inspecting source documents to test key attributes of the claims data.
- We compared claim development patterns and cost assumptions used in the actuarial calculations for consistency with historical experience and current trends.
- We compared the mortality tables used in the actuarial calculations to publicly available information.

/s/ GRANT THORNTON LLP

We have served as the Partnership's auditor since 2021.

Tulsa, Oklahoma
February 26, 2026

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

DECEMBER 31, 2025 AND 2024

(In thousands, except unit data)

	December 31,	
	2025	2024
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	\$ 71,212	\$ 136,962
Trade receivables (net of allowance of \$5,360 and \$2,087, respectively)	129,686	166,829
Other receivables	1,992	10,158
Inventories, net	142,619	120,661
Advance royalties	10,496	11,422
Digital assets	51,834	45,037
Prepaid expenses and other assets	22,215	22,161
Total current assets	430,054	513,230
PROPERTY, PLANT AND EQUIPMENT:		
Property, plant and equipment	4,502,648	4,435,535
Less accumulated depreciation, depletion and amortization	(2,364,206)	(2,269,265)
Total property, plant and equipment, net	2,138,442	2,166,270
OTHER ASSETS:		
Advance royalties	72,412	70,264
Equity method investments	69,638	35,532
Equity securities	82,466	92,541
Operating lease right-of-use assets	17,065	15,871
Other long-term assets	43,711	22,022
Total other assets	285,292	236,230
TOTAL ASSETS	\$ 2,853,788	\$ 2,915,730
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	\$ 81,809	\$ 98,188
Accrued taxes other than income taxes	20,319	21,051
Accrued payroll and related expenses	31,244	26,946
Accrued interest	2,012	1,821
Workers' compensation and pneumoconiosis benefits	15,901	14,838
Other current liabilities	29,495	48,023
Current maturities, long-term debt, net	23,646	22,275
Total current liabilities	204,426	233,142
LONG-TERM LIABILITIES:		
Long-term debt, excluding current maturities, net	427,137	450,885
Pneumoconiosis benefits	100,740	120,152
Workers' compensation	37,742	37,177
Asset retirement obligations	153,247	155,156
Long-term operating lease obligations	14,591	13,638
Deferred income tax liabilities	27,732	29,353
Other liabilities	27,951	22,694
Total long-term liabilities	789,140	829,055
Total liabilities	993,566	1,062,197
COMMITMENTS AND CONTINGENCIES - (Note 16)		
PARTNERS' CAPITAL:		
ARLP Partners' Capital:		
Limited Partners - Common Unitholders 128,428,024 and 128,061,981 units outstanding, respectively	1,843,627	1,867,850
Accumulated other comprehensive loss	(1,026)	(35,103)
Total ARLP Partners' Capital	1,842,601	1,832,747
Noncontrolling interest	17,621	20,786
Total Partners' Capital	1,860,222	1,853,533
TOTAL LIABILITIES AND PARTNERS' CAPITAL	\$ 2,853,788	\$ 2,915,730

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME
FOR THE YEARS ENDED DECEMBER 31, 2025, 2024 AND 2023
(In thousands, except unit and per unit data)

	Year Ended December 31,		
	2025	2024	2023
SALES AND OPERATING REVENUES:			
Coal sales	\$ 1,932,515	\$ 2,111,803	\$ 2,210,210
Oil & gas royalties	137,849	138,311	137,751
Transportation revenues	36,612	112,590	142,290
Other revenues	87,835	86,004	76,450
Total revenues	2,194,811	2,448,708	2,566,701
EXPENSES:			
Operating expenses (excluding depreciation, depletion and amortization)	1,368,521	1,507,398	1,368,787
Transportation expenses	36,612	112,590	142,290
Outside coal purchases	21,820	35,791	36,149
General and administrative	83,119	82,224	79,096
Depreciation, depletion and amortization	299,436	285,446	267,982
Asset impairments	—	31,130	—
Total operating expenses	1,809,508	2,054,579	1,894,304
INCOME FROM OPERATIONS	385,303	394,129	672,397
Interest expense (net of interest capitalized of \$10,663, \$12,843 and \$6,706, respectively)	(39,735)	(35,229)	(36,091)
Interest income	2,751	7,222	9,394
Net income (loss) on equity method investments	20,976	(4,961)	(1,468)
Change in fair value of digital assets	(4,354)	22,395	—
Impairment loss on investments - (Note 10)	(28,037)	—	—
Other income (expense)	(889)	(2,062)	218
INCOME BEFORE INCOME TAXES	336,015	381,494	644,450
INCOME TAX EXPENSE	18,765	15,937	8,280
NET INCOME	317,250	365,557	636,170
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	(6,087)	(4,702)	(6,052)
NET INCOME ATTRIBUTABLE TO ARLP	\$ 311,163	\$ 360,855	\$ 630,118
NET INCOME ATTRIBUTABLE TO ARLP			
GENERAL PARTNER	\$ —	\$ —	\$ 1,384
LIMITED PARTNERS	\$ 311,163	\$ 360,855	\$ 628,734
EARNINGS PER LIMITED PARTNER UNIT - BASIC AND DILUTED	\$ 2.40	\$ 2.77	\$ 4.81
WEIGHTED-AVERAGE NUMBER OF UNITS OUTSTANDING – BASIC AND DILUTED	128,387,910	127,964,744	127,180,312

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
FOR THE YEARS ENDED DECEMBER 31, 2025, 2024 AND 2023
(In thousands)

	Year Ended December 31,		
	2025	2024	2023
NET INCOME	\$ 317,250	\$ 365,557	\$ 636,170
OTHER COMPREHENSIVE INCOME (LOSS):			
Defined benefit pension plan			
Amortization of prior service cost (1)	9	186	186
Net actuarial gain	7,351	8,507	2,894
Amortization of net actuarial loss (1)	—	383	682
Total defined benefit pension plan adjustments	7,360	9,076	3,762
Pneumoconiosis benefits			
Net actuarial gain (loss)	25,571	13,990	(25,615)
Amortization of net actuarial loss (1)	928	3,356	1,382
Total pneumoconiosis benefits adjustments	26,499	17,346	(24,233)
Foreign currency translation adjustment	218	—	—
OTHER COMPREHENSIVE INCOME (LOSS)	<u>34,077</u>	<u>26,422</u>	<u>(20,471)</u>
COMPREHENSIVE INCOME	351,327	391,979	615,699
Less: Comprehensive income attributable to noncontrolling interest	<u>(6,087)</u>	<u>(4,702)</u>	<u>(6,052)</u>
COMPREHENSIVE INCOME ATTRIBUTABLE TO ARLP	<u>\$ 345,240</u>	<u>\$ 387,277</u>	<u>\$ 609,647</u>

(1) Amortization of prior service cost and actuarial loss is included in the computation of net periodic benefit cost (see Notes 13 and 14 for additional details).

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2025, 2024 AND 2023
(In thousands)

	Year Ended December 31,		
	2025	2024	2023
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	\$ 317,250	\$ 365,557	\$ 636,170
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	299,436	285,446	267,982
Non-cash compensation expense	8,874	10,614	12,864
Coal inventory adjustment to market	4,868	24,568	33,296
Net loss (income) on equity method investments	(20,976)	4,961	1,468
Distributions from equity method investments	10,761	2,377	2,567
Net gain on sale of property, plant and equipment	(1,543)	(262)	(3,230)
Asset impairment	—	31,130	—
Change in deferred income tax	(884)	(2,185)	(8,973)
Change in fair value of digital assets	4,354	(22,395)	—
Other non-cash change in digital assets	(11,151)	(10,358)	(12,516)
Impairment loss on investments	28,037	—	—
Other	20,276	20,844	10,316
Changes in operating assets and liabilities:			
Trade receivables	37,241	115,793	(41,210)
Other receivables	8,166	(1,201)	(1,077)
Inventories, net	(20,004)	(22,243)	(78,004)
Prepaid expenses and other assets	(10)	(3,068)	4,108
Advance royalties	(1,222)	(2,781)	(3,636)
Accounts payable	(5,620)	(19,223)	17,842
Accrued taxes other than income taxes	(727)	44	(1,960)
Accrued payroll and related benefits	4,297	(2,938)	(9,739)
Pneumoconiosis benefits	7,207	9,199	3,924
Workers' compensation	1,508	(105)	(1,477)
Other	(39,002)	19,357	(4,484)
Total net adjustments	333,886	437,574	188,061
Net cash provided by operating activities	651,136	803,131	824,231
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property, plant and equipment:			
Capital expenditures	(263,280)	(428,741)	(379,338)
Change in accounts payable and accrued liabilities	(10,826)	9,142	(29,695)
Proceeds from sale of property, plant and equipment	2,541	1,626	3,710
Contributions to equity method investments	(25,384)	(2,896)	(2,518)
Purchase of equity securities	(14,925)	—	(49,560)
Purchase of debt securities	(3,037)	—	—
JC Resources acquisition	—	—	(64,999)
Oil & gas reserve business combinations	(10,000)	—	(14,459)
Oil & gas reserve asset acquisitions	(7,837)	(24,733)	(24,225)
Other	1,493	4,938	7,762
Net cash used in investing activities	(331,255)	(440,664)	(553,322)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Borrowings under securitization facility	84,000	75,000	—
Payments under securitization facility	(84,000)	(75,000)	—
Proceeds from equipment financings	—	54,626	—
Payments on equipment financings	(12,870)	(11,981)	(24,970)
Borrowings under revolving credit facilities	—	20,000	—
Payments under revolving credit facilities	—	(20,000)	—
Borrowing under long-term debt	—	400,000	75,000
Payments on long-term debt	(14,063)	(299,842)	(129,455)
Payment of debt issuance costs	—	(11,442)	(12,376)
Payments for purchases of units under unit repurchase program	—	—	(19,432)
Payments for purchase of units and tax withholdings related to settlements under deferred compensation plans	(7,082)	(15,544)	(10,334)
Cash settlement of grants under deferred compensation plans	—	(21,786)	—
Excess purchase price over the contributed basis from JC Resources acquisition	—	—	(7,251)
Cash retained by JC Resources in acquisition	—	—	(2,933)
Distributions paid to Partners	(337,178)	(363,430)	(364,579)
Other	(14,537)	(15,919)	(10,789)
Net cash used in financing activities	(385,730)	(285,318)	(507,119)
Effect of exchange rate changes on cash and cash equivalents	99	—	—
NET CHANGE IN CASH AND CASH EQUIVALENTS	(65,750)	77,149	(236,210)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	136,962	59,813	296,023
CASH AND CASH EQUIVALENTS AT END OF PERIOD	\$ 71,212	\$ 136,962	\$ 59,813

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL
FOR THE YEARS ENDED DECEMBER 31, 2025, 2024 AND 2023
(In thousands, except unit data)

	Number of Limited Partner Units	Limited Partners' Capital	General Partner's Capital	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total Partners' Capital
Balance at January 1, 2023	127,195,219	\$ 1,656,025	\$ 66,548	\$ (41,054)	\$ 26,507	\$ 1,708,026
Comprehensive income:						
Net income	—	628,734	1,384	—	6,052	636,170
Actuarially determined long-term liability adjustments	—	—	—	(20,471)	—	(20,471)
Total comprehensive income						615,699
Settlement of deferred common unit-based compensation plans	860,060	(10,334)	—	—	—	(10,334)
Purchase of units under unit repurchase program	(929,842)	(19,432)	—	—	—	(19,432)
Common unit-based compensation	—	12,864	—	—	—	12,864
Distributions on deferred common unit-based compensation	—	(8,530)	—	—	—	(8,530)
Distributions from consolidated company to noncontrolling interest	—	—	—	—	(8,464)	(8,464)
JC Resources acquisition	—	(7,251)	(64,999)	—	—	(72,250)
Cash retained by JC Resources in acquisition	—	—	(2,933)	—	—	(2,933)
Distributions to Partners	—	(356,049)	—	—	—	(356,049)
Balance at December 31, 2023	127,125,437	1,896,027	—	(61,525)	24,095	1,858,597
Cumulative-effect adjustment - See Note 2	—	6,232	—	—	—	6,232
Comprehensive income:						
Net income	—	360,855	—	—	4,702	365,557
Actuarially determined long-term liability adjustments	—	—	—	26,422	—	26,422
Total comprehensive income						391,979
Settlement of deferred common unit-based compensation plans	936,544	(37,330)	—	—	—	(37,330)
Common unit-based compensation	—	10,614	—	—	—	10,614
Distributions on deferred common unit-based compensation	—	(5,514)	—	—	—	(5,514)
Distributions from consolidated company to noncontrolling interest	—	—	—	—	(8,011)	(8,011)
Distributions to Partners	—	(357,916)	—	—	—	(357,916)
Other	—	(5,118)	—	—	—	(5,118)
Balance at December 31, 2024	128,061,981	1,867,850	—	(35,103)	20,786	1,853,533
Comprehensive income:						
Net income	—	311,163	—	—	6,087	317,250
Actuarially determined long-term liability adjustments	—	—	—	34,077	—	34,077
Total comprehensive income						351,327
Settlement of deferred common unit-based compensation plans	366,043	(7,082)	—	—	—	(7,082)
Common unit-based compensation	—	8,874	—	—	—	8,874
Distributions on deferred common unit-based compensation	—	(3,522)	—	—	—	(3,522)
Distributions from consolidated company to noncontrolling interest	—	—	—	—	(9,252)	(9,252)
Distributions to Partners	—	(333,656)	—	—	—	(333,656)
Balance at December 31, 2025	128,428,024	\$ 1,843,627	\$ —	\$ (1,026)	\$ 17,621	\$ 1,860,222

See notes to consolidated financial statements.

ALLIANCE RESOURCE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2025, 2024 AND 2023

1. ORGANIZATION AND PRESENTATION

Significant Relationships Referenced in Notes to Consolidated Financial Statements

- References to “we,” “us,” “our” or “ARLP Partnership” mean the business and operations of Alliance Resource Partners, L.P., the parent company, as well as its consolidated subsidiaries.
- References to “ARLP” mean Alliance Resource Partners, L.P., individually as the parent company, and not on a consolidated basis.
- References to “MGP” mean Alliance Resource Management GP, LLC, ARLP’s general partner.
- References to “Mr. Craft” mean Joseph W. Craft III, the Chairman, President and Chief Executive Officer of MGP.
- References to “Intermediate Partnership” mean Alliance Resource Operating Partners, L.P., the intermediate partnership of Alliance Resource Partners, L.P.
- References to “Alliance Coal” mean Alliance Coal, LLC, an indirect wholly owned subsidiary of ARLP.
- References to “Alliance Minerals” mean Alliance Minerals, LLC, an indirect wholly owned subsidiary of ARLP.
- References to “Alliance Resource Properties” mean Alliance Resource Properties, LLC, an indirect wholly owned subsidiary of ARLP.

Organization

ARLP is a Delaware limited partnership listed on the NASDAQ Global Select Market under the ticker symbol “ARLP.” ARLP was formed in May 1999 and completed its initial public offering on August 19, 1999 when it acquired substantially all of the coal production and marketing assets of Alliance Resource Holdings, Inc., a Delaware corporation (“ARH”), and its subsidiaries. We are managed by our general partner, MGP, a Delaware limited liability company, which holds a non-economic general partner interest in ARLP. Alliance GP, LLC, which is indirectly wholly owned by Mr. Craft, is the direct owner of MGP.

Acquisitions

JC Resources

On February 22, 2023, we acquired 2,682 oil & gas net royalty acres in the Delaware Basin from JC Resources LP (“JC Resources”), an entity owned by Mr. Craft, for \$72.3 million (“JC Resources Acquisition”).

Skyland

On December 7, 2023, we acquired 2,372 oil & gas net royalty acres in the Anadarko, Williston and Delaware Basins from Skyland Minerals, L.P. (“Skyland”) and Haymaker Minerals & Royalties II, LLC (“Haymaker”) for a purchase price of \$14.5 million (“Skyland Acquisition”).

Elk Range

On October 31, 2025, we acquired approximately 190 oil & gas net royalty acres in the Midland and Delaware Basins from 89 Energy II Minerals, LLC (“89 Energy”) for a purchase price of \$10.0 million (“Elk Range Acquisition”).

The JC Resources, Skyland and Elk Range Acquisitions enhanced our ownership position in various basins and furthered our business strategy to grow our Oil & Gas Royalties segment through accretive acquisitions. See Note 4 – Acquisitions for more information.

Other Growth Investments

Infinitum

On September 8, 2023, we purchased shares of Series E Preferred Stock (“Series E Preferred Stock”) for \$24.6 million in Infinitum Electric, Inc. (“Infinitum”), a Texas-based startup developer and manufacturer of electric motors featuring printed circuit board stators that have the potential to result in motors that are smaller, lighter, quieter, more efficient and capable of operating at a fraction of the carbon footprint of conventional electric motors. On December 31, 2025, we purchased shares of Series F Preferred Stock (“Series F Preferred Stock”) for \$14.9 million in Infinitum. For more information on this investment, please see Note 10 – Investments.

Gavin Generation

In February 2025, we committed to invest up to \$25.0 million of limited partner interests in Gavin Generation Holdings A, LP (“Gavin Generation”). Gavin Generation owns, indirectly, an interest in a joint venture holding company formed with a third party that indirectly owns and operates a coal-fired power plant. For more information on this investment, please see Note 3 – Variable Interest Entities.

The Infinitum and Gavin Generation investments further our business strategy to pursue opportunities that support the growth and development of energy and related infrastructure and leverage our core competencies and build platforms for future lines of business with long-term growth and cash flow generation.

Presentation

The consolidated financial statements include the accounts and operations of the ARLP Partnership and present our financial position as of December 31, 2025 and 2024, and results of our operations, comprehensive income, cash flows and changes in partners’ capital for each of the three years in the period ended December 31, 2025. All of our intercompany transactions and accounts have been eliminated.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Variable Interest Entity (“VIE”)

VIEs are primarily entities that lack sufficient equity to finance their activities without additional financial support from other parties or whose equity holders, as a group, lack one or more of the following characteristics: (a) direct or indirect ability to make decisions, (b) obligation to absorb expected losses or (c) right to receive expected residual returns. A VIE must be evaluated quantitatively and qualitatively to determine the primary beneficiary, which is the reporting entity that has (a) the power to direct activities of a VIE that most significantly impact the VIE’s economic performance and (b) 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 primary beneficiary is required to consolidate the VIE for financial reporting purposes.

To determine a VIE’s primary beneficiary, we perform a qualitative assessment to determine which party, if any, has the power to direct activities of the VIE and the obligation to absorb losses and/or receive its benefits. This assessment involves identifying the activities that most significantly impact the VIE’s economic performance and determine whether it, or another party, has the power to direct those activities. When evaluating whether we are the primary beneficiary of a VIE, we perform a qualitative analysis that considers the design of the VIE, the nature of our involvement and the variable interests held by other parties.

Business Combinations

A business consists of inputs and processes applied to those inputs that have the ability to contribute to the creation of outputs. We account for the acquisition of a business as a business combination, where we record the assets acquired, including identified intangible assets and liabilities assumed at their fair value, which in many instances involves estimates based on third-party valuations, such as appraisals, or internal valuations based on discounted cash flow analyses or other valuation techniques. However, if substantially all the fair value of the assets acquired is concentrated in a single

identifiable asset or a group of similar identifiable assets with the same risk profile, the acquisition is accounted for as an asset acquisition and recorded at cost.

Estimates

The preparation of consolidated financial statements in conformity with generally accepted accounting principles of the United States requires management to make estimates and assumptions that affect the reported amounts and disclosures in the consolidated financial statements. Actual results could differ from those estimates. Significant estimates and assumptions include:

- Asset retirement obligations;
- Pension obligations;
- Workers' compensation and pneumoconiosis obligations;
- Acquisition related purchase price allocations;
- Life of mine assumptions;
- Oil & gas reserve quantities and carrying amounts;
- Determination of oil & gas revenue accruals; and
- Contingent consideration liability.

Fair Value Measurements

We apply fair value measurements to certain assets and liabilities. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Fair value is based on assumptions that market participants would use when pricing an asset or liability, including assumptions about risk and risks inherent in valuation techniques and inputs to valuations. Fair value measurements assume that the transaction occurs in the principal market for the asset or liability or, in the absence of a principal market, the most advantageous market for the asset or liability (the market for which the reporting entity would be able to maximize the amount received or minimize the amount paid). Valuation techniques used in our fair value measurements are based on observable and unobservable inputs. Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect our own market assumptions.

We use the following fair value hierarchy, which prioritizes the inputs to valuation techniques used to measure fair value into three broad levels:

- Level 1 – Quoted prices for identical assets and liabilities in active markets that we have the ability to access at the measurement date.
- Level 2 – Quoted prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model derived valuations whose inputs are observable or whose significant value drivers are observable.
- Level 3 – Unobservable inputs for the asset or liability including situations where there is little, if any, market activity for the asset or liability.

The fair value hierarchy gives the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall into different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement requires judgment, considering factors specific to the asset or liability. Significant fair value measurements are used in our significant estimates and are discussed throughout these notes.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand and on deposit, including highly liquid investments with maturities of three months or less. At times the ARLP Partnership maintains deposits in federally insured financial institutions in excess of stated federally insured limits.

Cash Management

The cash flows from operating activities section of our consolidated statements of cash flows reflects adjustments of \$3.3 million and \$6.7 million representing book overdrafts at December 31, 2024 and 2023, respectively. We did not have material book overdrafts at December 31, 2025.

Inventories

Coal inventories are stated at the lower of cost or net realizable value on a first-in, first-out basis. Supply, finished goods, work in process and raw materials inventories are stated at an average cost basis, less a reserve for obsolete and surplus items.

Advance Royalties

Rights to coal mineral leases are often acquired and/or maintained through advance royalty payments. Where royalty payments represent prepayments recoupable against future production, they are recorded as an asset, with amounts expected to be recouped within one year classified as a current asset. As mining occurs on these leases, the royalty prepayments are charged to operating expenses. We assess the recoverability of royalty prepayments based on estimated future production. Royalty prepayments estimated to be nonrecoverable are expensed. Our advance royalties are summarized as follows:

	December 31,	
	2025	2024
	(in thousands)	
Advance royalties, affiliates (see Note 21– Related-Party Transactions)	\$ 69,126	\$ 67,189
Advance royalties, third-parties	13,782	14,497
Total advance royalties	<u>\$ 82,908</u>	<u>\$ 81,686</u>

Digital Assets

We began our crypto-mining activities during the second half of 2020 as we started mining bitcoin as a pilot project to monetize already paid for, yet underutilized, electricity load. We continue to periodically be awarded digital assets through our crypto-mining activities. The awards are accounted for as revenue and valued at the exchange quoted price at the time they are awarded. Beginning January 1, 2024, with our adoption of the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) 2023-08, *Intangibles - Goodwill and Other - Crypto Assets (Subtopic 350-60)* (“ASU 2023-08”), the digital assets we hold are subsequently remeasured to fair value based on the exchange quoted price as of the balance sheet date and included on our consolidated balance sheets within the *Digital assets* line item. The activity from remeasurement of digital assets to fair value is reflected in our consolidated statements of income within the *Change in fair value of digital assets* line item. Digital assets sold for cash nearly immediately after they are awarded to us for mining activities are presented as cash flows from operating activities, while other sales are reflected as cash flows from investing activities in our consolidated statements of cash flows. Our realized gains or losses are determined as the difference between the proceeds received when the digital assets are sold and our cost basis in the digital assets. Our cost basis is the value of the digital assets when they are awarded less any impairment recognized prior to our adoption of ASU 2023-08. We use a first-in, first-out methodology to assign costs to our digital assets in the calculation of our realized gains or losses. See Note 7 – Digital Assets for additional information.

Property, Plant and Equipment

Expenditures which extend the useful lives of existing plant and equipment assets are capitalized. Interest costs associated with major asset additions are capitalized during the construction period. Maintenance and repairs that do not extend the useful life or increase productivity of the asset are charged to operating expense as incurred. Exploration expenditures are charged to operating expense as incurred, including costs related to drilling and study costs incurred to convert or upgrade mineral resources to reserves. Processing facilities and mineral rights, assuming current production estimates, are depreciated or depleted using the units-of-production method. Mining equipment and other plant and equipment assets are depreciated principally using the straight-line method over the remaining estimated life of each mine.

Buildings, office equipment and improvements are amortized straight line over their estimated useful lives. Gains or losses arising from retirements are included in operating expenses. Depletion of coal mineral rights is provided on the basis of tonnage mined in relation to estimated recoverable tonnage, which equals estimated proven and probable coal mineral reserves. Therefore, our coal mineral rights are depleted based on only proven and probable coal mineral reserves. See *Oil & Gas Reserve Quantities and Carrying Amounts* below for a discussion of our accounting policies for oil & gas properties.

Mine Development Costs

Mine development costs are capitalized until production, other than production incidental to the mine development process, commences and are amortized on a units of production method based on the estimated proven and probable coal mineral reserves. Mine development costs represent costs incurred in establishing access to coal mineral reserves and include costs associated with sinking or driving shafts and underground drifts, permanent excavations, roads and tunnels. The end of the development phase and the beginning of the production phase takes place when construction of the mine for economic extraction is substantially complete. Coal extracted during the development phase is incidental to the mine's production capacity and is not considered to shift the mine into the production phase.

Long-Lived Asset Impairment

We review the carrying value of long-lived assets and certain identifiable intangibles whenever events or changes in circumstances indicate that the carrying amount of an asset group may not be recoverable based on estimated undiscounted future cash flows. To the extent the carrying amount of an asset group is not recoverable based on undiscounted cash flows, the amount of impairment is measured by the difference between the carrying value and the fair value (See Note 9 – Long-Lived Asset Impairments).

Oil & Gas Reserve Quantities and Carrying Amounts

We are wholly dependent on third-party operators to explore, develop, produce and operate the properties associated with our mineral interests. We follow the successful efforts method of accounting for our oil & gas mineral interests. Under this method, costs to acquire mineral interests in oil & gas properties are capitalized when incurred. The costs of mineral interests in unproved properties are capitalized pending the results of exploration and leasing efforts by operators. As mineral interests in unproved properties are determined to be proved, the related costs are transferred to proved oil & gas properties.

Mineral interests in oil & gas properties are grouped using a reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, which we may also refer to as a depletable group. Mineral interests in proved oil & gas properties are depleted based on the units-of-production method. Proved reserves are quantities of oil & gas that can be estimated with reasonable certainty to be recoverable in the future from a given date forward, from known reservoirs, under existing economic conditions, operating methods, and government regulations. Proved developed resources are the quantities expected to be recovered through the operators' existing wells with existing equipment, infrastructure and operating methods.

We evaluate impairment of our oil & gas mineral interests in proved properties whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. This evaluation is performed on a depletable group basis. We compare the undiscounted projected future cash flows expected in connection with a depletable group to its unamortized carrying amount to determine recoverability. When the carrying amount of a depletable group exceeds its estimated undiscounted future cash flows, the carrying amount is written down to its fair value, which is measured as the present value of the projected future cash flows of such properties. The factors used to determine fair value include estimates of proved reserves, future commodity prices, timing of future production, future expenditures, and a risk-adjusted discount rate.

Our oil & gas mineral interests in unproved properties are also assessed for impairment periodically but at least annually when facts and circumstances indicate that the unproved property will not be transferred to proved properties. Impairment of individual unproved properties whose acquisition costs are relatively significant are assessed on a property-by-property basis, and an impairment loss is recognized if we determine that the unproved property will not be transferred to proved properties. Impairment of unproved properties whose acquisition costs are not individually significant are assessed on a group basis. Any amount of loss to be recognized and the amount of a valuation allowance needed to provide for impairment of those properties is determined by amortizing those properties in the aggregate on the basis of historical

experience and other relevant information, such as the relative proportion of such properties on which proved reserves have been found in the past.

Upon the sale of a complete depletable group, the book value thereof, less proceeds or salvage value, are charged to income. Upon the sale or retirement of an aggregation of interests which make up less than a complete depletable group, the proceeds are credited to accumulated depreciation, depletion and amortization, unless doing so would significantly alter the depreciation, depletion and amortization rate of the depletable group, in which case a gain or loss would be recorded.

Investments

Our investments and ownership interests in equity securities without readily determinable fair values in entities in which we do not have a controlling financial interest or significant influence are accounted for using a measurement alternative other than fair value. The measurement alternative is historical cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions for identical or similar investments of the same entity. Distributions received on those investments are recorded as income unless those distributions are considered a return on investment, in which case the historical cost is reduced. We account for our ownership interests in Infinitum and Ascend Elements, Inc. (“Ascend”) as equity securities without readily determinable fair values. See Note 10 – Investments for further discussion of these investments.

Our investments and ownership interests in entities in which we do not have a controlling financial interest are accounted for under the equity method of accounting if we have the ability to exercise significant influence over the entity. Investments accounted for under the equity method are initially recorded at cost, and the difference between the basis of our investment and the underlying equity in the net assets of the entity at the investment date, if any, is amortized over the lives of the related assets that gave rise to the difference.

In the event our investments contain complex distribution structures, we use the hypothetical liquidation at book value (“HLBV”) method or other reasonable allocation method to determine the appropriate allocation of income or loss that reflects the economics over the life of the investment and upon liquidation. Under the HLBV method, income or loss of the investee is allocated based on hypothetical amounts that each investor would be entitled to receive if the net assets held were liquidated at book value at the end of each period, adjusted for any contributions made and distributions received during the period.

We hold equity method investments in AllDale Minerals III, LP (“AllDale III”), Francis Renewable Energy, LLC (“Francis”), NGP Energy Transition IV, L.P. (“NGP ET IV”) and Gavin Generation. See Note 3 – Variable Interest Entities for further discussion of our equity method investments.

We review our investments for impairment whenever events or changes in circumstances indicate a loss in the value of the investment may be other-than-temporary.

Leases

We lease buildings and equipment under operating lease agreements that provide for the payment of minimum rentals. We also have noncancelable lease agreements with third parties for land and equipment under finance lease obligations. Some of our arrangements within these agreements have both lease and non-lease components, which are generally accounted for separately. We have elected a practical expedient to account for lease and non-lease components as a single lease component for leases of buildings and office equipment. Our leases have approximate lease terms of 1 to 36 years, some of which include automatic renewals up to ten years, which are likely to be exercised and some of which include options to terminate the lease within one year. We also hold numerous mineral reserve leases with both related parties as well as third parties, none of which are accounted for as an operating lease or as a finance lease.

We review each agreement to determine if an arrangement within the agreement contains a lease at the inception of an arrangement. Once an arrangement is determined to contain an operating or finance lease with a term greater than 12 months, we recognize a lease liability for the obligation to make lease payments and a right-of-use asset for the right to use the underlying asset for the lease term based on the present value of lease payments over the lease term. The lease term includes all noncancelable periods defined in the lease as well as periods covered by options to extend the lease that we are reasonably certain to exercise. As an implicit borrowing rate cannot be determined under most of our leases, we use

our incremental borrowing rate based on the information available at commencement date in determining the present value of lease payments.

Expenses related to leases determined to be operating leases will be recognized on a straight-line basis over the lease term including any reasonably assured renewal periods, while those determined to be finance leases will be recognized following a front-loaded expense profile in which interest and amortization are presented separately in the income statement. The determination of whether a lease is accounted for as a finance lease or an operating lease requires management to make estimates primarily about the fair value of the asset and its estimated economic useful life.

Capitalized Implementation Costs of Cloud-Based Software

Costs incurred in the implementation of cloud-based software arrangements, including the costs of the software, materials, consultants, and payroll and payroll related costs for employees incurred are capitalized. Planning costs incurred prior to the implementation of these arrangements and costs not qualifying for capitalization are charged to expense when incurred. Capitalized implementation costs are amortized on a straight-line basis over their useful life. We have capitalized \$10.9 million in implementation costs related to various cloud-based software arrangements. Because none of the cloud-based software arrangements had begun as of December 31, 2025, no amortization expense has been recognized for the years ended December 31, 2025, 2024 and 2023. Our capitalized implementation costs of cloud-based software arrangements are included in *Other long-term assets* on our consolidated balance sheets.

Common Unit-Based Compensation

We maintain the Long-Term Incentive Plan (“LTIP”) for certain key employees and executive officers. Pursuant to the LTIP, unit awards of non-vested “phantom” or notional units, also referred to as “restricted units,” may be granted, which, upon satisfaction of time and performance-based vesting requirements, entitle the LTIP participant to receive ARLP common units. Certain awards may also contain a minimum-value guarantee payable in ARLP common units or cash that would be paid regardless of whether the awards vest, as long as service requirements are met. Annual grant levels, vesting provisions and minimum-value guarantees of restricted units for designated participants are recommended by Mr. Craft, subject to review and approval by the compensation committee of our general partner (“Compensation Committee”). The vesting of all restricted units is subject to the satisfaction of certain financial tests. Assuming the financial tests are met, restricted units issued to LTIP participants generally cliff vest on January 1st of the third year following the issuance of such restricted units. We expect to settle restricted unit grants by issuing ARLP common units, except for the portion of the restricted units that will satisfy our tax withholding obligations. As provided under the distribution equivalent rights (“DERs”) provisions of the LTIP and the terms of the restricted unit awards, all currently outstanding non-vested restricted units include contingent rights to receive quarterly distributions in cash or, at the discretion of the Compensation Committee, phantom units in lieu of cash credited to a bookkeeping account with a value equal to the cash distributions we make to unitholders during the vesting period.

The fair value of restricted common unit grants under the LTIP are determined on the grant date of the award and recognized as compensation expense over the requisite service period. The corresponding liability is classified as equity and included in limited partners’ capital in the consolidated financial statements. If it is not probable that the restricted units will vest for a particular grant, any previously expensed amounts for that grant are reversed, and no future expense will be recognized for that grant other than amounts provided for under minimum-value guarantees. We account for forfeitures of non-vested restricted unit grants as they occur. If vesting is no longer considered probable for a particular grant, any previously paid DER amounts for that grant are reversed from Partners’ Capital and recorded as compensation expense and any future DERs, for that grant, if any, will be recognized as compensation expense when paid.

We utilized the Supplemental Executive Retirement Plan (“SERP”) to provide deferred compensation benefits for certain executive officers. All allocations made to participants under the SERP were made in the form of “phantom” ARLP units. The SERP was administered by the Compensation Committee.

Our directors participated in the MGP Amended and Restated Deferred Compensation Plan for Directors (“Directors’ Deferred Compensation Plan”). Pursuant to the Directors’ Deferred Compensation Plan, for amounts deferred either automatically or at the election of the director, a notional account was established and credited with notional common units of ARLP, described in the Directors’ Deferred Compensation Plan as “phantom” units.

For both the SERP and Directors' Deferred Compensation Plan, when quarterly cash distributions were made with respect to ARLP common units, an amount equal to such quarterly distribution was credited to each participant's notional account as additional phantom units and recorded as compensation expense. All grants of phantom units under the SERP and Directors' Deferred Compensation Plan vested immediately.

On December 16, 2024, the SERP and Directors' Deferred Compensation Plan were terminated, and final distributions of applicable plan accounts were settled in cash. We have no further obligations under the SERP or the Directors' Deferred Compensation Plan.

Workers' Compensation and Pneumoconiosis (Black Lung) Benefits

We are liable for workers' compensation benefits for traumatic injuries and benefits for black lung disease (or pneumoconiosis). Both traumatic claims and pneumoconiosis benefits are covered through our self-insured programs.

We provide income replacement and medical treatment for work-related traumatic injury claims as required by applicable state laws. Workers' compensation laws also compensate survivors of workers who suffer employment related deaths. Our liability for traumatic injury claims is the estimated present value of current workers' compensation benefits, based on our actuarial estimates. Our actuarial calculations are based on a blend of actuarial projection methods and numerous assumptions including claim development patterns, mortality, medical costs and interest rates.

Our pneumoconiosis benefits liability is calculated using the service cost method based on the actuarial present value of the estimated pneumoconiosis obligation. Our actuarial calculations are based on numerous assumptions including claim development patterns, medical costs and mortality. Actuarial gains or losses are amortized over the remaining service period of active miners.

Pension Benefits

The funded status of our pension benefit plan is recognized separately in our consolidated balance sheets as an asset. The funded status is the difference between the fair value of plan assets and the plan's benefit obligation. In December 2025, we entered into a pension buy-in transaction with an insurance carrier by purchasing a buy-in contract to secure pension benefits for plan participants. The buy-in contract is accounted for as a plan asset as we retain the underlying pension obligation. Subsequent to the buy-in, we measure the pension obligation at an amount equal to the fair value of the buy-in contract, reflecting the rate at which the obligation could be effectively settled. Accordingly, the discount rate used to measure the obligation reflects the rate at which the obligation could be effectively settled, as evidenced by the pricing of the buy-in contract. Prior to the buy-in, pension obligations and net periodic benefit costs were actuarially determined and impacted by various assumptions and estimates including expected return on assets, discount rates, mortality assumptions, employee turnover rates and retirement dates.

The expected long-term rate of return on plan assets is determined based on broad equity and bond indices, the investment goals and objectives, the target investment allocation and on the average annual total return for each asset class. As of December 31, 2025 (first effective for 2026), this includes the expected return of the buy-in contract which is consistent with the discount rate used to measure the related benefit obligation, as the contract is designed to generate cash flows that reimburse the plan for benefit payments.

Unrecognized actuarial gains and losses and unrecognized prior service costs and credits are deferred and recorded in accumulated other comprehensive loss until amortized as a component of net periodic benefit cost. Unrecognized actuarial gains and losses in excess of 10% of the greater of the benefit obligation or the market-related value of plan assets are amortized over the participants' average remaining future years of service.

Asset Retirement Obligations

Our coal mining operations are governed by various state statutes and the Federal Surface Mining Control and Reclamation Act of 1977, which establish reclamation and mine closing standards. These regulations require, among other things, restoration of property in accordance with specified standards and an approved reclamation plan. We record a liability for the fair value of an asset retirement obligation in the period incurred or acquired and a corresponding amount is capitalized as part of the related long-lived asset and depreciated on a units-of-production basis. As changes in estimates occur (such as mine plan revisions, changes in estimated costs or changes in anticipated timing of reclamation activities),

adjustments to the obligation and asset are recognized at the present value of the change in obligation. For locations that have been fully depleted or closed, the present value of the change in obligation is recorded to operating expenses. Accretion of the asset retirement obligation is recognized over time and until reclamation obligations are satisfied.

Asset retirement obligations primarily relate to mine site reclamation activities, which includes permanently sealing portals at underground mines, reclaiming the final pits for both our underground mines and past surface mines, removing or covering refuse piles and settling ponds, water treatment, and dismantling preparation plants, other facilities and roadway infrastructure. Federal and state laws require bonds to secure our obligations to reclaim lands used for mining and are typically renewed on an annual basis.

Coal Revenue Recognition

Revenues from coal supply contracts with customers, which primarily relate to sales of thermal coal, are recognized at the point in time when control of the coal passes to the customer. We have determined that each ton of coal represents a separate and distinct performance obligation. Our coal supply contracts and other revenue contracts vary in length from short-term to long-term sales contracts and do not typically have significant financing components. Transportation revenues represent the fulfillment costs incurred for the services provided to customers through third-party carriers and for which we are directly reimbursed. Other revenues primarily consist of transloading fees, administrative service revenues from our affiliates, mine safety services and products, other coal contract fees and other handling and service fees. Performance obligations under these contracts are typically satisfied upon transfer of control of the goods or services to our customer which is determined by the contract and could be upon shipment or upon delivery.

The estimated transaction price from each of our contracts is based on the total amount of consideration we expect to be entitled to under the contract. Included in the transaction price for certain coal supply contracts is the impact of variable consideration, including quality price adjustments, handling services, government imposition claims, per ton price fluctuations based on certain coal sales price indices and anticipated payments in lieu of shipments. We have constrained the expected value of variable consideration in our estimation of transaction price and only included this consideration to the extent that it is probable that a significant revenue reversal will not occur. The estimated transaction price for each contract is allocated to our performance obligations based on relative standalone selling prices determined at contract inception. Variable consideration is allocated to a specific part of the contract in many instances, such as if the variable consideration is based on production activities for coal delivered during a certain period or the outcome of a customer's ability to accept coal shipments over a certain period.

Contract assets are recorded as trade receivables and reported separately in our consolidated balance sheet from other contract assets as title passes to the customer and our right to consideration becomes unconditional. Payments for coal shipments are typically due within two to four weeks of performance. We typically do not have material contract assets that are stated separately from trade receivables as our performance obligations are satisfied as control of the goods or services passes to the customer thereby granting us an unconditional right to receive consideration. Contract liabilities relate to consideration received in advance of the satisfaction of our performance obligations. Contract liabilities are recognized as revenue at the point in time when control of the good or service passes to the customer.

Oil & Gas Revenue Recognition

Oil & gas royalty revenues are recognized at the point in time when control of the product is transferred to the purchaser by the lessee and collectability of the sales price is reasonably assured. Oil & gas are priced on the delivery date based on prevailing market prices with certain adjustments related to oil quality and physical location. The royalty we receive is tied to a market index, with certain adjustments based on, among other factors, whether a well connects to a gathering or transmission line, quality and heat content of the product, and prevailing supply and demand conditions.

We also periodically earn revenue from lease bonuses. We recognize lease bonus revenue when we execute a lease of our mineral interests to exploration and production companies. A lease agreement represents our contract with an operator, which is generally an exploration and production company. The contract will (a) generally transfer the rights to any oil or gas discovered, (b) grant us a right to a specified royalty interest from the operator, and (c) require the operator to commence drilling and complete operations within a specified time period. Control of the minerals transfers to the operator when the lease agreement is executed. At the time we execute the lease agreement, we expect to receive the lease bonus payment within a reasonable time, though in no case more than one year, such that we do not adjust the expected amount of consideration for the effects of any significant financing component.

As a non-operator, we have limited visibility into the timing of when new wells start producing. In addition, production statements may not be received for 30 to 90 days or more after the date production is delivered. As a result, we are required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. The expected sales volumes and prices from our mineral interests are estimated and included in the *Trade receivables* line item in our consolidated balance sheets. The difference between our estimates and the actual amounts received for oil & gas royalty revenue are immaterial and recorded in the month that payment is received unless new production information is received prior to the payment allowing us to update the estimate recorded.

Income Taxes

We are not a taxable entity for federal or state income tax purposes; the tax effect of our activities accrues to our unitholders. Although publicly traded partnerships as a general rule are taxed as corporations, we qualify for an exemption because at least 90% of our income consists of qualifying income, as defined in Section 7704(c) of the Internal Revenue Code. Net income for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under our partnership agreement. Individual unitholders have different investment bases depending upon the timing and price of acquisition of their partnership units. Furthermore, each unitholder's tax accounting, which is partially dependent upon the unitholder's tax position, differs from the accounting followed in our consolidated financial statements. Accordingly, the aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined because information regarding each unitholder's tax attributes in our partnership is not available to us.

Our subsidiary Alliance Minerals within our Oil & Gas Royalties segment and certain other subsidiaries within our Other, Corporate and Elimination category are subject to federal and state income taxes. We use the liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (i) temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities and (ii) operating losses and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax status or a change in tax rates on deferred tax assets and liabilities is recognized in the period the change in status is elected or rate change is enacted. A valuation allowance is provided for deferred tax assets when it is more likely than not the deferred tax assets will not be realized.

New Accounting Standards Issued and Adopted

In December 2023, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2023-09, *Income Taxes (Topic 740): Improvements to Income Tax Disclosures* ("ASU 2023-09"). ASU 2023-09 primarily requires enhanced disclosures to (1) disclose specific categories in the rate reconciliation, (2) disclose the amount of income taxes paid and expensed disaggregated by federal, state, and foreign taxes, with further disaggregation by individual jurisdictions if certain criteria are met, and (3) disclose income (loss) from continuing operations before income tax (benefit) disaggregated between domestic and foreign. The adoption of ASU 2023-09 did not have a material effect on our consolidated financial statements. The new disclosure requirements were applied prospectively beginning with the year ended December 31, 2025. See Note 22 – Income Taxes.

New Accounting Standards Issued and Not Yet Adopted

In November 2024, the FASB issued ASU 2024-03, *Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures (Subtopic 220-40)* ("ASU 2024-03"). ASU 2024-03 requires the disclosure of additional information about specific expense categories in the notes to the financial statements to provide enhanced transparency into the nature and function of expenses. ASU 2024-03 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. We are currently evaluating the impact ASU 2024-03 will have on our consolidated financial statements and related disclosures.

In September 2025, the FASB issued ASU 2025-06, *Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Targeted Improvements to the Accounting for Internal-Use Software* ("ASU 2025-06"). ASU 2025-06 improves the accounting for software development costs by removing references to software development stages so that the accounting is neutral to different software development methods. ASU 2025-06 is effective for fiscal years beginning

after December 15, 2027 and interim periods within those fiscal years, with early adoption permitted. ASU 2025-06 can be applied on a prospective basis, a modified basis for in-process projects or a retrospective basis. We are evaluating the impact of ASU 2025-06 on our results of operations, cash flows, financial condition and related disclosures.

3. VARIABLE INTEREST ENTITIES

AllDale I & II and Cavalier Minerals

We own the general partner interests and, including the limited partner interests we hold through our ownership in Cavalier Minerals JV, LLC (“Cavalier Minerals”), approximately 97% of the limited partner interests in AllDale Minerals LP (“AllDale I”) and AllDale Minerals II, LP (“AllDale II”, and collectively with AllDale I, “AllDale I & II”). As the general partner of AllDale I & II, we are entitled to receive 20.0% of all distributions from AllDale I & II with the remaining 80.0% allocated to limited partners based upon ownership percentages.

Cavalier Minerals owns approximately 72% of the limited partner interests in AllDale I & II. We own the managing member interest and a 96% member interest in Cavalier Minerals. Bluegrass Minerals Management, LLC (“Bluegrass Minerals”) owns a 4% member interest in Cavalier Minerals and a profits interest which entitles it to receive distributions equal to 25% of all distributions (including in liquidation).

We have concluded that AllDale I, AllDale II and Cavalier Minerals are VIEs which we consolidate as the primary beneficiary because we have the power to direct the activities that most significantly impact the economic performance of AllDale I, AllDale II and Cavalier Minerals in addition to having substantial equity ownership.

Our share of Cavalier Minerals’ investment in AllDale I & II is eliminated in consolidation and Bluegrass Minerals’ investment in Cavalier Minerals is accounted for as noncontrolling ownership interest on our consolidated balance sheets. Additionally, earnings attributable to Bluegrass Minerals are recognized as noncontrolling interest in our consolidated statements of income.

The following table presents the carrying amounts and classification of AllDale I & II’s assets and liabilities included in our consolidated balance sheets:

	December 31,	
	2025	2024
	(in thousands)	
Assets (liabilities):		
Cash and cash equivalents	\$ 4,137	\$ 5,154
Trade receivables	11,194	11,209
Total property, plant and equipment, net	356,751	373,093
Accounts payable	(236)	(221)
Accrued taxes other than income taxes	(970)	(870)

AllDale III

AllDale III owns oil & gas mineral interests in areas around the oil & gas mineral interests we own. Alliance Minerals owns a 13.9% limited partner interest in AllDale III. Alliance Minerals’ investment in AllDale III is subject to a 25% profits interest for the general partner that is subject to a return hurdle equal to the greater of 125% of cumulative capital contributions and a 10% internal rate of return, and following an 80/20 “catch-up” provision for the general partner.

We have concluded that AllDale III is a VIE that we do not consolidate. AllDale III is structured as a limited partnership with the limited partners (1) not having the ability to remove the general partner and (2) not participating significantly in operational decisions. We are not the primary beneficiary of AllDale III because we do not have the power to direct the activities that most significantly impact AllDale III’s economic performance. At December 31, 2025 and 2024, the carrying value of our investment in AllDale III was \$21.0 million and \$22.5 million, respectively.

Francis

We invested \$20 million in Francis, in the form of a convertible note. Francis currently is active in the installation, management and operation of metered-for-fee, public-access electric vehicle (“EV”) charging stations. Francis also develops and constructs EV charging stations for third-party customers. Our convertible note matured on April 1, 2023 and was converted into a preferred equity interest in Francis. As of December 31, 2025, we held approximately 15.2% of Francis’ equity.

We have concluded that Francis is a VIE that we do not consolidate. Francis’ management structure is similar to a limited partnership with the non-managing members (i) not having the ability to remove the managing member and (ii) not participating significantly in the operational decisions. We are not the primary beneficiary of Francis because we do not have the power to direct the activities that most significantly impact Francis’s economic performance. At December 31, 2025, the carrying value of our investment in Francis was zero. At December 31, 2024, the carrying value of our investment in Francis was \$4.3 million.

NGP ET IV

We have a commitment to purchase \$25.0 million of limited partner interests in NGP ET IV, a private equity fund sponsored by NGP Energy Capital Management, LLC (“NGP”) and focused on investments that are part of the energy transition. This commitment represents a 3.6% interest in NGP ET IV. As of December 31, 2025, we have funded \$10.8 million of this commitment after giving effect to returns on our investment.

We have concluded that NGP ET IV is a VIE that we do not consolidate. NGP ET IV is structured as a limited partnership with limited partners (i) not having the ability to remove the general partner and (ii) not participating significantly in operational decisions. We are not the primary beneficiary of NGP ET IV because we do not have the power to direct the activities that most significantly impact NGP ET IV’s economic performance. At December 31, 2025 and 2024, the carrying value of our investment in NGP ET IV was \$13.4 million and \$8.8 million, respectively.

Gavin Generation

We have committed to invest up to \$25.0 million of limited partner interests in Gavin Generation. Gavin Generation owns, indirectly, an interest in a joint venture holding company formed with a third-party that indirectly owns and operates a coal-fired power plant. This commitment represents an interest of 5.4% in Gavin Generation (based on total commitments). As of December 31, 2025, we have funded \$17.3 million of this commitment after giving effect to returns on our investment. Our investment in Gavin Generation is subject to a customary profit interest in favor of the general partner after the return of capital to the limited partners and the investment generating a specified internal rate of return in favor of the limited partners.

We have concluded that Gavin Generation is a VIE that we do not consolidate. Gavin Generation is structured as a limited partnership with the limited partners (1) not having the ability to remove the general partner and (2) not participating significantly in operational decisions. We are not the primary beneficiary of Gavin Generation because we do not have the power to direct the activities that most significantly impact Gavin Generation’s economic performance. At December 31, 2025, the carrying value of our investment in Gavin Generation was \$35.2 million.

4. ACQUISITIONS

JC Resources

On February 22, 2023, we completed the JC Resources Acquisition, which gave us increased exposure to a prolific area of the Delaware Basin that was within close proximity to reserves that we already owned. This acquisition was approved by the conflicts committee of MGP’s board of directors, which is comprised entirely of independent directors. Because JC Resources was under common control with us, we recorded the acquisition at JC Resources’ carrying value for each period presented. The carrying value of the mineral interests as well as related receivables and payables at February 22, 2023 was \$65.0 million inclusive of \$25.4 million and \$37.8 million of mineral interests in proved and unproved properties, respectively.

Acquisition Agreement

During 2023 and 2024, we were party to a collaborative agreement with a third party for the acquisition of oil & gas mineral interests in the Midland and Delaware Basins. Under the agreement, the third party assisted us in the identification, evaluation, and acquisition of target oil & gas mineral interests. In exchange for these services, the third party received a participation share, partially funded by the third party, and was paid a periodic management fee. Pursuant to this agreement, we purchased \$5.8 million and \$10.7 million of oil & gas mineral interests in proved and unproved properties, respectively, during the year ended December 31, 2024 and \$6.5 million and \$6.7 million in proved and unproved properties, respectively, during the year ended December 31, 2023. Management fees paid under this agreement were immaterial.

Skyland Acquisition

On December 7, 2023 (the “Skyland Acquisition Date”), we acquired 2,372 oil & gas net royalty acres in the Anadarko, Williston and Delaware Basins from Skyland and Haymaker for a cash purchase price of \$14.5 million which was funded with cash on hand. This acquisition further enhanced our ownership position in these basins. Because the mineral interests acquired in the Skyland Acquisition include royalty interests in both developed properties and undeveloped properties with different risk profiles, we have determined that the acquisition should be accounted for as a business combination and the underlying assets should be recorded at fair value as of the Skyland Acquisition Date on our consolidated balance sheet.

The following table summarizes the fair value allocation of assets acquired as of the Skyland Acquisition Date:

	(in thousands)
Mineral interests in proved properties	\$ 8,694
Mineral interests in unproved properties	5,765
	<u>\$ 14,459</u>

The fair value of the mineral interests was determined using an income approach consisting of a discounted cash flow model. The assumptions used in the discounted cash flow model included estimated production, projected cash flows, forward oil & gas prices and risk adjusted discount rates. Certain assumptions used are not observable in active markets; therefore, the fair value measurements represent Level 3 fair value measurements.

The amounts of revenue and earnings from the mineral interests acquired in the Skyland Acquisition included in our consolidated statements of income from the Skyland Acquisition Date through December 31, 2023 are immaterial.

The following represents our supplemental pro forma consolidated revenues and net income for the year ended December 31, 2023 as if the mineral interests acquired in the Skyland Acquisition had been included in our consolidated results since January 1, 2023. These amounts have been calculated after applying our accounting policies.

	Year Ended December 31, 2023
	(in thousands) (unaudited)
Revenues	\$ 2,568,516
Net income	637,757

Elk Range Acquisition

On October 31, 2025 (the “Elk Range Acquisition Date”), we acquired 190 oil & gas net royalty acres in the Midland and Delaware Basins from 89 Energy for a cash purchase price of \$10.0 million which was funded with cash on hand. This acquisition further enhanced our ownership position in Permian Basin. Because the mineral interests acquired in the Elk Range Acquisition include royalty interests in both developed properties and undeveloped properties with different risk profiles, we have determined that the acquisition should be accounted for as a business combination and the underlying assets should be recorded at fair value as of the Elk Range Acquisition Date on our consolidated balance sheet.

The following table summarizes the fair value allocation of assets acquired as of the Elk Range Acquisition Date:

	(in thousands)
Mineral interests in proved properties	\$ 7,222
Mineral interests in unproved properties	2,778
	<u>\$ 10,000</u>

The fair value of the mineral interests was determined using an income approach consisting of a discounted cash flow model. The assumptions used in the discounted cash flow model included estimated production, projected cash flows, forward oil & gas prices and risk adjusted discount rates. Certain assumptions used are not observable in active markets; therefore, the fair value measurements represent Level 3 fair value measurements.

The amounts of revenue and earnings from the mineral interests acquired in the Elk Range Acquisition included in our consolidated statements of income from the Elk Range Acquisition Date through December 31, 2025 are immaterial.

The following represents our supplemental pro forma consolidated revenues and net income for the years ended December 31, 2025 and 2024 as if the mineral interests acquired in the Elk Range Acquisition had been included in our consolidated results since January 1, 2024. These amounts have been calculated after applying our accounting policies.

	Year Ended December 31,	
	2025	2024
	(in thousands) (unaudited)	
Revenues	\$ 2,196,135	\$ 2,450,336
Net income	307,341	367,047

5. FAIR VALUE MEASUREMENTS

The following table summarizes certain fair value measurements within the hierarchy not included elsewhere in these notes:

			Fair Value		
	Carrying Value		Level 1	Level 2	Level 3
			(in thousands)		
December 31, 2025					
Recorded on a recurring basis:					
Digital assets	\$ 51,834	\$ 51,834	\$ —	\$ —	
Contingent consideration	\$ 18,000	\$ —	\$ —	\$ 18,000	
Additional disclosures:					
Long-term debt	\$ 463,456	\$ —	\$ 508,844	\$ —	
December 31, 2024					
Recorded on a recurring basis:					
Digital assets	\$ 45,037	\$ 45,037	\$ —	\$ —	
Contingent consideration	\$ 13,100	\$ —	\$ —	\$ 13,100	
Additional disclosures:					
Long-term debt	\$ 490,387	\$ —	\$ 523,461	\$ —	

The carrying amounts for cash equivalents, accounts receivable, accounts payable, accrued and other liabilities, approximate fair value due to the short maturity of those instruments.

The fair value of our digital assets is based on an exchange quoted price. See Note 7 – Digital Assets for more information on our digital assets.

The fair value measurement of our contingent consideration liability is determined using an option approach methodology simulation based on significant inputs not observable in active markets representing a Level 3 fair value measurement under the fair value hierarchy. Our contingent consideration liability is associated with our acquisition of our Hamilton County Coal, LLC (“Hamilton”) mine in 2015 wherein we agreed to pay the seller additional consideration for the acquisition if the average quarterly sales price exceeds a defined threshold price in any future quarter subject to a maximum of \$110.0 million reduced for any payments made under an overriding royalty agreement with the sellers relating to mineral interests controlled by our Hamilton mine. We have paid \$16.1 million under this contingent consideration agreement and \$0.7 million under the overriding royalty agreement as of December 31, 2025.

The estimated fair value of our long-term debt, including current maturities, is based on interest rates that we believe are currently available to us in active markets for issuance of debt with similar terms and remaining maturities. See Note 12 – Long-Term Debt for additional information on our long-term debt.

Quantitative Information about Level 3 Fair Value Measurements

Contingent Consideration

Our option approach methodology simulation generates an expected payment for each quarter in Hamilton’s expected mine life by using proprietary internal estimates of our uncommitted coal sales prices and generating a simulated uncommitted coal sales price by applying unobservable inputs through a million simulations. This simulated coal sales price is then used in a calculation of the expected future payments using our proprietary committed coal sales prices and production for each quarter. We then calculate the present value of the estimated future payments. The following table presents quantitative information about certain significant unobservable inputs used in the fair value measurement for our contingent consideration liability. The use of significant unobservable inputs results in uncertainty as of the reporting date, as changes in these unobservable inputs could significantly raise or lower the estimated fair value.

	Valuation Technique(s)	Unobservable Input	Range/Amount (Average) (a)
December 31, 2025			
Contingent Consideration	Option approach methodology simulation	Cost of Debt	5.46% - 8.35%
		Coal price volatility	9.2%
		Market price of risk adjustment (annual)	6.7%
December 31, 2024			
Contingent Consideration	Option approach methodology simulation	Cost of Debt	6.51% - 8.56%
		Coal price volatility	6.2%
		Market price of risk adjustment (annual)	6.2%

(a) Averages represent the arithmetic average of the inputs and is not weighted by a relative fair value or notional amount.

The following table represents changes in our contingent consideration liability:

	Year Ended December 31,	
	2025	2024
	(in thousands)	
Beginning balance	\$ 13,100	\$ 9,900
Noncash changes in fair value (1)	11,340	10,989
Payments	(6,440)	(7,789)
Ending balance	<u>\$ 18,000</u>	<u>\$ 13,100</u>

(1) Noncash changes in the fair value of our contingent consideration liability are included in the *Operating expenses (excluding depreciation, depletion and amortization)* line item within our consolidated statements of income.

6. INVENTORIES

Inventories consist of the following:

	December 31,	
	2025	2024
	(in thousands)	
Coal	\$ 61,528	\$ 37,290
Finished goods (net of reserve for obsolescence of \$1,133 and \$2,481, respectively)	9,732	14,197
Work in process	2,660	1,560
Raw materials	6,106	7,192
	<u>80,026</u>	<u>60,239</u>
Supplies (net of reserve for obsolescence of \$6,901 and \$6,409, respectively)	62,593	60,422
Total inventories, net	<u>\$ 142,619</u>	<u>\$ 120,661</u>

The above coal inventory balances reflect lower of cost or net realizable value adjustments of \$4.9 million and \$24.6 million as of December 31, 2025 and 2024, respectively. The adjustment as of December 31, 2025 is the result of higher cost per ton at the Mettiki Coal, LLC and Mettiki Coal (WV), LLC (collectively “Mettiki”) mining complex due to lower production and challenging geological conditions in the longwall panel that reduced coal recovery. The adjustment as of December 31, 2024 is the result of lower coal sale prices and higher cost per ton primarily due to a longwall move at the Hamilton mining complex, lower production at Mettiki and MC Mining LLC (“MC Mining”) mining complexes, and ongoing development activities at the Henderson County mine at our River View Coal, LLC (“River View”) mining complex.

7. DIGITAL ASSETS

The following table sets forth our digital assets as shown on the consolidated balance sheet:

	December 31, 2025			December 31, 2024		
	Units	Cost Basis	Fair Value	Units	Cost Basis	Fair Value
Digital assets:	(in thousands, except unit data)					
Bitcoin	592.01	\$ 29,937	\$ 51,834	481.89	\$ 18,748	\$ 45,037
Total		<u>\$ 29,937</u>	<u>\$ 51,834</u>		<u>\$ 18,748</u>	<u>\$ 45,037</u>

The following table represents a reconciliation of the fair values of our digital assets:

	Year Ended December 31,	
	2025	2024
Digital assets:	(in thousands)	
Beginning balance	\$ 45,037	\$ 15,811
Additions	11,182	10,428
Dispositions	(31)	(3,597)
Net fair value gains	—	22,395
Net fair value losses	(4,354)	—
Ending balance	<u>\$ 51,834</u>	<u>\$ 45,037</u>

Our beginning balance on January 1, 2024 is inclusive of a cumulative-effect adjustment of \$6.2 million. Additions are the result of awarded digital assets received from our crypto-mining activities, while dispositions are the result of sales and payments for services. During the year ended December 31, 2024, we had digital asset dispositions of \$3.6 million, inclusive of realized gains of \$2.1 million. We did not have material digital asset dispositions during the year ended December 31, 2025.

8. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consist of the following:

	December 31,	
	2025	2024
	(in thousands)	
Mining equipment and processing facilities	\$ 2,322,784	\$ 2,131,697
Land and coal mineral rights	510,790	508,892
Oil & gas mineral interests	895,920	878,083
Buildings, office equipment, improvements and other miscellaneous equipment	345,402	315,092
Construction, mine development and other projects in progress	84,820	213,579
Mine development costs	342,932	388,192
Property, plant and equipment, at cost	4,502,648	4,435,535
Less accumulated depreciation, depletion and amortization	(2,364,206)	(2,269,265)
Total property, plant and equipment, net	<u>\$ 2,138,442</u>	<u>\$ 2,166,270</u>

All of our property, plant and equipment have depreciable lives of 1 to 36 years. Depreciation, depletion and amortization expense related to property, plant and equipment was \$306.5 million, \$287.1 million and \$276.4 million for the years ended December 31, 2025, 2024 and 2023, respectively.

At December 31, 2025 and 2024, land and coal mineral rights above include \$10.3 million and \$14.1 million, respectively, of carrying value associated with coal mineral reserves and resources attributable to properties where we or a third party to which we lease coal mineral reserves and resources are not currently engaged in mining operations or leasing to third parties, and therefore, the coal mineral reserves are not currently being depleted. We believe that the carrying value of these coal mineral reserves will be recovered.

At December 31, 2025 and 2024, our oil & gas mineral interests noted in the table above include the carrying value of our unproved oil & gas mineral interests totaling \$360.7 million and \$377.5 million, respectively. We generally do not record depletion expense for our unproved oil & gas mineral interests; however, we do review for impairment as needed throughout the year.

We incurred \$18.5 million and \$67.2 million in mine development costs, primarily related to Hamilton and Tunnel Ridge, LLC (“Tunnel Ridge”) mining complexes for the years ended December 31, 2025 and 2024 respectively. All past capitalized mine development costs are associated with other mines that shifted to the production phase in past years and

we are amortizing these costs accordingly. We believe that the carrying value of the past development costs will be recovered.

9. LONG-LIVED ASSET IMPAIRMENTS

On November 15, 2024, we issued Worker Adjustment and Retraining Notification Act notices to the employees of our MC Mining mining complex, which is primarily included in our Appalachia Coal Operations reportable segment. The notices were issued primarily in response to market uncertainty, challenging geology and higher costs which led to the decision to reduce production at the mine. Accordingly, we adjusted the carrying value of MC Mining's assets from \$101.3 million to its fair value of \$70.2 million resulting in an impairment charge of \$31.1 million.

The fair value of the impaired assets was determined using a cost replacement approach, which represents a Level 3 fair value measurement under the fair value hierarchy. The fair value analysis used quoted prices obtained from external sources as adjusted to account for the remaining useful life of the assets.

10. INVESTMENTS

Equity Method Investments

The changes in our equity method investments were as follows:

	Year Ended December 31,		
	2025	2024	2023
		(in thousands)	
Beginning balance	\$ 35,532	\$ 46,503	\$ 49,371
Contributions	25,384	2,896	2,518
Net income (loss) on equity method investments	20,976	(4,961)	(1,468)
Distributions received	(12,254)	(3,788)	(3,918)
Change in our share of net assets	—	(5,118)	—
Ending balance	<u>\$ 69,638</u>	<u>\$ 35,532</u>	<u>\$ 46,503</u>

Net income (loss) on equity method investments represents our share of the income or loss of the equity method investments.

Change in our share of net assets represents a reduction in our position in the investments due to additional capital contributions from other investors.

Infinitum

As of December 31, 2025 we have an investment in Infinitum of \$82.5 million. Infinitum is a Texas-based startup developer and manufacturer of electric motors featuring printed circuit board stators. During 2022, we purchased shares of Series D Preferred Stock in Infinitum for \$42.0 million. On September 8, 2023, we purchased shares of Series E Preferred Stock in Infinitum for \$24.6 million at a slightly higher price per share than our Series D Preferred Stock, resulting in an immaterial increase in the carrying value of our investment. On December 31, 2025, we purchased shares of Series F Preferred Stock (together with the Series D and Series E Preferred Stock, the "Infinitum Preferred Stock") in Infinitum for \$14.9 million.

The Infinitum Preferred Stock provides for non-cumulative dividends when and if declared by Infinitum's board of directors and is convertible, at any time, at our option, into shares of common stock of Infinitum. We account for our investment in Infinitum as an equity investment without a readily determinable fair value. Absent an observable price change, it is not practicable to estimate the fair value of our investment in Infinitum because of the lack of a quoted market price for our ownership interests. Therefore, we use a measurement alternative other than fair value to account for our investment.

The value per share of the Series F Preferred Stock will not be determined until the funding round is completed in the first quarter of 2026. Additionally, the Series D and Series E Preferred Stock contain anti-dilution provisions such that we

will receive additional shares designed to maintain our original investments in each respective funding round. Because the value per share of the Series F Preferred Stock was not yet determined as of December 31, 2025, we are unable to determine if a remeasurement of our investment is warranted or how many additional Series D and Series E Preferred Stock shares we will receive.

Ascend

On August 22, 2023, we purchased shares of Series D Preferred Stock in Ascend, a U.S.-based manufacturer and recycler of sustainable, engineered battery materials for electric vehicles, for \$25.0 million. This investment was accounted for as an equity investment without a readily determinable fair value because of the lack of quoted market prices. In June 2025, Ascend raised new capital through a convertible note financing. Under the terms of the convertible note and the resulting recapitalization, all existing shares of each outstanding series of preferred stock were converted into common stock on a 1:1 basis for stockholders that participated in the convertible note purchase, or on a 3:1 basis if they did not participate. We determined in June 2025 that the common stock we hold in Ascend as a result of the conversion had no value. This resulted in an impairment charge of \$25.0 million included in our consolidated statements of income.

The \$25.0 million impairment charge is a Level 3 fair value measurement and is included within our Other, Corporate and Elimination category. We determined the impairment charge using a combination of market approaches and option-pricing models. The underlying enterprise value was estimated using income and market approaches which utilize discounted cash flows and market participant values for assets in hypothetical sales scenarios. The enterprise value was then utilized in market approach models and option-pricing models taking into account the rights and preferences of the common stock, expected exit scenarios, and volatility associated with such outcomes to arrive at a fair value. The following table presents quantitative information about certain significant unobservable inputs used in this fair value measurement:

	<u>Valuation Technique(s)</u>	<u>Unobservable Input</u>	<u>Range/Amount (Average) (a)</u>
Common Stock	Option-pricing approach methodology	Industry volatility	29.10% - 70.86% (49.98%)
		Estimated time to exit	2.0 - 4.0 (3.0) years
	Income approach methodology	Forecasted future cash flow	\$906.6 - \$1,285.9 (\$1,096.3) (in millions)
		Cost of capital	11.25% - 16.58% (13.92%)

(a) Averages represent the arithmetic average of the inputs and is not weighted by a relative fair value or notional amount.

We elected to participate in the June 2025 recapitalization of Ascend by purchasing \$3.0 million of its convertible notes to enhance the seniority of our investment through a debt instrument and improve the potential recovery of a portion of our original investment. The convertible notes provide for a redemption in two years for an amount equal to the greater of (a) a multiple of each stockholder's investment in the convertible notes as determined by the level of participation and (b) the principal amount of each stockholder's investment in the convertible notes plus an annual interest rate of 15%. Based on our level of participation, our convertible notes provide for a multiple of 12 times our funded commitment at redemption.

In December 2025, Ascend issued additional convertible notes senior to our convertible notes with similar multiples. As a result of this issuance and lack of visibility at year-end into Ascend's financial condition and performance, we believe it is unlikely we will recover our \$3.0 million convertible note investment and therefore fully impaired the investment in December 2025. This impairment charge represents a Level 3 fair value measurement and is included within our Other, Corporate and Elimination category. Because of the lack of visibility into Ascend's financial condition and performance at year-end, we were unable to utilize the market approaches or option-pricing models that are discussed above. Instead, the impairment was based on qualitative factors, including the seniority of the subsequently issued convertible notes and the lack of observable inputs.

11. LEASES

The components of lease expense were as follows:

	December 31,		
	2025	2024	2023
	(in thousands)		
Finance lease cost:			
Amortization of right-of-use assets	\$ 96	\$ 95	\$ 96
Interest on lease liabilities	16	22	27
Operating lease cost	3,325	3,573	3,572
Short-term lease cost	1,678	2,139	450
Variable lease cost	1,723	1,694	1,680
Total lease cost	<u>\$ 6,838</u>	<u>\$ 7,523</u>	<u>\$ 5,825</u>

Supplemental cash flow information related to leases was as follows:

	December 31,		
	2025	2024	2023
	(in thousands)		
Cash paid for amounts included in the measurement of lease liabilities:			
Operating cash flows for operating leases	\$ 3,299	\$ 3,668	\$ 3,720
Operating cash flows for finance leases	\$ 16	\$ 22	\$ 27
Financing cash flows for finance leases	\$ 124	\$ 119	\$ 363
Right-of-use assets obtained in exchange for lease obligations:			
Operating leases	\$ 3,730	\$ 1,080	\$ 2,596

Supplemental balance sheet information related to leases was as follows:

	December 31,	
	2025	2024
	(in thousands)	
Finance leases:		
Property and equipment finance lease assets, gross	\$ 1,085	\$ 1,085
Accumulated depreciation	(698)	(602)
Property and equipment finance lease assets, net	<u>\$ 387</u>	<u>\$ 483</u>
	December 31,	
	2025	2024
Weighted average remaining lease term		
Operating leases	13.8 years	14.8 years
Finance leases	2.0 years	3.0 years
Weighted average discount rate		
Operating leases	6.1 %	6.1 %
Finance leases	4.8 %	4.8 %

Maturities of lease liabilities as of December 31, 2025 were as follows:

	<u>Operating leases</u>	<u>Finance leases</u>
	(in thousands)	
2026	\$ 3,223	\$ 140
2027	3,190	140
2028	2,481	—
2029	1,685	—
2030	1,182	—
Thereafter	14,386	—
Total lease payments	26,147	280
Less imputed interest	(8,829)	(18)
Total	<u>\$ 17,318</u>	<u>\$ 262</u>

The current portion of our operating and finance lease obligations are included in *Other current liabilities* line item in our consolidated balance sheets. The long-term portion of our finance lease obligation is included in the *Other liabilities* line item in our consolidated balance sheets.

12. LONG-TERM DEBT

Long-term debt consists of the following:

	<u>Principal</u>		<u>Unamortized Discount and</u>
	<u>December 31,</u>		<u>Debt Issuance Costs</u>
	<u>2025</u>	<u>2024</u>	<u>December 31,</u>
			<u>2025</u>
			<u>2024</u>
	(in thousands)		
Revolving credit facility	\$ —	\$ —	\$ (5,007)
Term loan	31,640	45,703	(884)
8.625% Senior notes due 2029	400,000	400,000	(6,782)
Securitization facility	—	—	—
February 2024 equipment financing	31,816	44,684	—
	463,456	490,387	(12,673)
Less current maturities	(28,041)	(26,669)	4,395
Total long-term debt	<u>\$ 435,415</u>	<u>\$ 463,718</u>	<u>\$ (8,278)</u>
			<u>\$ (12,833)</u>

Credit Facility

On January 13, 2023, Alliance Coal, as borrower, entered into a credit agreement with various financial institutions which was amended on June 12, 2024 (the “Credit Agreement”). The Credit Agreement provides for a \$425.0 million revolving credit facility which includes a sublimit of \$15.0 million for swingline borrowings and permits the issuance of letters of credit up to the full amount of the Credit Facility (the “Revolving Credit Facility”), and for a term loan in an aggregate principal amount of \$75.0 million (the “Term Loan”). The Revolving Credit Facility also includes an incremental facility providing for an increase of \$100.0 million at our option subject to lenders agreeing to participate in such incremental facility. The Credit Agreement matures on March 9, 2028, at which time the aggregate outstanding principal amount of all Revolving Credit Facility advances and all Term Loan advances are required to be repaid in full. Interest is payable quarterly, with principal on the Term Loan due in quarterly installments equal to 6.25% of the outstanding balance of the Term Loan on the Credit Agreement amendment date beginning with the quarter ended June 30, 2024. We incurred debt issuance costs during the years ended December 31, 2024 and 2023 of \$1.8 million and \$12.4 million, respectively, in connection with the Credit Agreement. These debt issuance costs are deferred and amortized as a component of interest expense over the term of the Revolving Credit Facility.

The Credit Agreement is guaranteed by ARLP and certain of its subsidiaries, including the Intermediate Partnership and most of the direct and indirect subsidiaries of Alliance Coal (the “Subsidiary Guarantors”). The Credit Agreement also is secured by substantially all of the assets of the Subsidiary Guarantors and Alliance Coal. Borrowings under the Credit

Agreement bear interest, at our option, at either (i) an adjusted one-month, three-month or six-month term rate based on the secured overnight financing rate published by the Federal Reserve Bank of New York, plus the applicable margin or (ii) the base rate plus the applicable margin. The base rate is the highest of (i) the Overnight Bank Funding Rate plus 0.50%, (ii) the Administrative Agent's prime rate, and (iii) the Daily Simple Secured Overnight Financing Rate plus 100 basis points. The applicable margin for borrowings under the Credit Agreement are determined by reference to the Consolidated Debt to Consolidated Cash Flow Ratio. For borrowings under the Term Loan, we elected the one-month term rate, with applicable margin, which was 7.27% as of December 31, 2025. At December 31, 2025, we had \$41.0 million of letters of credit outstanding with \$384.0 million available for borrowing under the Revolving Credit Facility. We incur an annual commitment fee of 0.50% on the undrawn portion of the Revolving Credit Facility. We utilize the Credit Agreement, as appropriate, for working capital requirements, capital expenditures and investments, scheduled debt payments and distribution payments.

The Credit Agreement contains various restrictions affecting Alliance Coal and its subsidiaries, including, among other things, restrictions on incurrence of additional indebtedness and liens, sale of assets, investments, mergers and consolidations and transactions with affiliates. In each case, these restrictions are subject to various exceptions. In addition, restrictions apply to cash distributions by Alliance Coal to the Intermediate Partnership if such distribution would result in exceeding the debt of Alliance Coal to cash flow ratio (as determined in the Credit Agreement) being more than 1.0 to 1.0 or in Alliance Coal having liquidity of less than \$200 million. The Credit Agreement requires us to maintain (a) a debt of Alliance Coal to cash flow ratio of not more than 1.5 to 1.0, (b) a consolidated debt of Alliance Coal and the Intermediate Partnership to cash flow ratio of not more than 2.5 to 1.0 and (c) an interest coverage ratio of not less than 3.0 to 1.0, in each case, during the four most recently ended fiscal quarters. The debt of Alliance Coal to cash flow ratio, consolidated debt of Alliance Coal and the Intermediate Partnership to cash flow ratio, and interest coverage ratio were 0.12 to 1.0, 0.90 to 1.0 and 41.29 to 1.0, respectively, for the trailing twelve months ended December 31, 2025. We were in compliance with the covenants of the Credit Agreement as of December 31, 2025 and anticipate remaining in compliance with the covenants.

Net restricted assets, as defined by the Securities and Exchange Commission, refers to the amount of our consolidated subsidiaries' net assets for which the ability to transfer funds to ARLP in the form of cash dividends, loans, advances, or transfers is restricted. As a result of the restrictions contained in the Credit Facility and its associated compliance ratios, the amount of our net restricted assets at December 31, 2025 was \$700.6 million.

8.625% Senior Notes due 2029

On June 12, 2024, the Intermediate Partnership and Alliance Resource Finance Corporation (as co-issuer), a wholly owned subsidiary of the Intermediate Partnership ("Alliance Finance"), issued an aggregate principal amount of \$400.0 million of senior unsecured notes due 2029 (the "2029 Senior Notes") in a private placement to qualified institutional buyers. The 2029 Senior Notes have a term of five years, maturing on June 15, 2029 and accrue interest at an annual rate of 8.625%. Interest is payable semi-annually in arrears on each June 15 and December 15. The 2029 Senior Notes are guaranteed, jointly and severally, on a senior unsecured basis by ARLP, certain of ARLP's wholly owned oil and gas and coal royalties subsidiaries and each of ARLP's subsidiaries that guarantee obligations under the Credit Agreement. The indenture governing the 2029 Senior Notes contains customary terms, events of default and covenants relating to, among other things, the incurrence of debt, the payment of distributions or similar restricted payments, undertaking transactions with affiliates and limitations on asset sales.

At any time prior to June 15, 2026, the issuers may redeem up to 35% of the aggregate principal amount of the 2029 Senior Notes at a redemption price equal to 108.625% of the principal amount redeemed, plus accrued and unpaid interest, if any, to, but excluding, the redemption date, with an amount of cash not greater than the net proceeds from one or more equity offerings. The issuers may also redeem all or a part of the 2029 Senior Notes at any time on or after June 15, 2026, at the redemption prices set forth in the indenture, plus accrued and unpaid interest, if any, to, but excluding, the redemption date. At any time prior to June 15, 2026, the issuers may redeem the 2029 Senior Notes at a redemption price equal to the principal amount plus a "make-whole" premium, plus accrued and unpaid interest, if any, to, but excluding, the redemption date.

In addition, if prior to June 15, 2026, a Specified Minerals Disposition (as defined in the indenture governing the 2029 Senior Notes and which involves oil and gas mineral interests) occurs, the issuers will be required to make an offer to purchase up to 40% of the aggregate principal amount of 2029 Senior Notes then outstanding at an offer price in cash in an amount equal to 108.625% of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of

purchase. We incurred debt issuance costs during the year ended December 31, 2024 of \$9.7 million in connection with the 2029 Senior Notes. These debt issuance costs are deferred and amortized as a component of interest expense over the term of the 2029 Senior Notes.

Accounts Receivable Securitization

Certain direct and indirect wholly owned subsidiaries of our Intermediate Partnership were party to a \$75.0 million accounts receivable securitization facility (“Securitization Facility”) that was scheduled to mature in January 2026. Under the Securitization Facility, certain subsidiaries sell certain trade receivables on an ongoing basis to our Intermediate Partnership, which then sells the trade receivables to AROP Funding, LLC (“AROP Funding”), a wholly owned bankruptcy-remote special purpose subsidiary of our Intermediate Partnership, which in turn borrows on a revolving basis up to \$75.0 million secured by the trade receivables. After the sale, Alliance Coal, as servicer of the assets, collects the receivables on behalf of AROP Funding. The Securitization Facility bears interest based on a short-term bank yield index. On December 31, 2025, we had \$11.7 million of letters of credit outstanding with \$63.3 million available for borrowing under the Securitization Facility. The agreement governing the Securitization Facility contains customary terms and conditions, including limitations with regards to certain customer credit ratings. In January 2026, we extended the term of the Securitization Facility to January 2027. At December 31, 2025, we did not have any outstanding borrowings under the Securitization Facility.

February 2024 Equipment Financing

On February 28, 2024, Alliance Coal entered into an equipment financing arrangement accounted for as debt, wherein Alliance Coal received \$54.6 million in exchange for conveying its interest in certain equipment owned indirectly by Alliance Coal and entering into a master lease agreement for that equipment (the “February 2024 Equipment Financing”). The February 2024 Equipment Financing contains customary terms and events of default and provides for forty-eight monthly payments with an implicit interest rate of 8.29%, maturing on February 28, 2028. Upon maturity, the equipment will revert to Alliance Coal.

Craft Foundation Installment Purchase Arrangement

On January 29, 2026, Alliance Resource Properties, as borrower, entered into an installment purchase arrangement with The Joseph W. Craft III Foundation, an entity controlled by Mr. Craft, for \$5.9 million pursuant to the purchase of certain coal reserves as discussed in Note 21 – Related-Party Transactions. The installment purchase arrangement contains customary terms and events of default and provides for six annual payments of \$1.2 million each, with an interest rate of 5.0%, beginning on January 1, 2027 and maturing on January 1, 2032. Alliance Resource Properties has the right at its option, as well as the obligation if demanded by The Joseph W. Craft III Foundation, to prepay all unpaid purchase price installments (together with accrued and unpaid interest thereon) at any time without penalty or premium.

Other

We also have an agreement with a bank to provide additional letters of credit in an amount of \$5.0 million to maintain surety bonds to secure certain asset retirement obligations and our obligations for workers’ compensation benefits. At December 31, 2025, we had \$5.0 million in letters of credit outstanding under this agreement.

Aggregate maturities of long-term debt as of December 31, 2025 are payable as follows:

Year Ended December 31,	(in thousands)
2026	\$ 28,041
2027	29,245
2028	6,170
2029	400,000
2030	—
	<u>\$ 463,456</u>

13. ACCRUED WORKERS' COMPENSATION AND PNEUMOCONIOSIS BENEFITS

The following is a reconciliation of the changes in workers' compensation liability (including current and long-term liability balances):

	December 31,	
	2025	2024
	(in thousands)	
Beginning balance	\$ 47,870	\$ 47,975
Changes in accruals	13,508	13,236
Payments	(14,944)	(14,473)
Interest accretion	2,275	2,037
Valuation loss (gain)	669	(905)
Ending balance	\$ 49,378	\$ 47,870

The discount rate used to calculate the estimated present value of future obligations for workers' compensation was 4.78% and 5.17% at December 31, 2025 and 2024, respectively.

The valuation loss in 2025 was primarily attributable to an unfavorable change in claims development and a decrease in the discount rate used to calculate the estimated present value of the future obligations. The valuation gain in 2024 was primarily attributable to a favorable change in claims development and an increase in the discount rate used to calculate the estimated present value of the future obligations.

As of December 31, 2025 and 2024, we had \$104.5 million and \$106.8 million, respectively, in surety bonds and letters of credit outstanding to secure workers' compensation obligations.

We limit our exposure to traumatic injury claims by purchasing a high-deductible insurance policy that starts paying benefits after deductibles for the particular claim year have been met. Our workers' compensation liability above is presented on a gross basis and does not include our expected receivables on our insurance policy. Our receivables for traumatic injury claims under this policy as of December 31, 2025 and 2024 were \$4.1 million and \$3.7 million, respectively. Our receivables are included in *Other long-term assets* on our consolidated balance sheets.

The following is a reconciliation of the changes in pneumoconiosis benefit obligations:

	December 31,	
	2025	2024
	(in thousands)	
Benefit obligations at beginning of year	\$ 124,297	\$ 132,444
Service cost	3,471	3,443
Interest cost	6,705	6,231
Actuarial gain	(25,571)	(13,990)
Benefits and expenses paid	(3,897)	(3,831)
Benefit obligations at end of year	\$ 105,005	\$ 124,297

The following is a reconciliation of the changes in the pneumoconiosis benefit obligation recognized in accumulated other comprehensive loss:

	Year Ended December 31,		
	2025	2024	2023
	(in thousands)		
Net actuarial gain (loss)	\$ 25,571	\$ 13,990	\$ (25,615)
Reversal of amortization item:			
Net actuarial loss	928	3,356	1,382
Total recognized in accumulated other comprehensive loss	\$ 26,499	\$ 17,346	\$ (24,233)

The discount rate used to calculate the estimated present value of future obligations for pneumoconiosis benefits was 5.49%, 5.51% and 4.81% at December 31, 2025, 2024 and 2023, respectively.

	Year Ended December 31,		
	2025	2024	2023
	(in thousands)		
Amount recognized in accumulated other comprehensive loss consists of:			
Net actuarial loss	\$ 5,900	\$ 32,399	\$ 49,745

The actuarial gain component of the change in benefit obligations in 2025 was primarily attributable to a) favorable assumption changes regarding future average medical benefits, b) favorable assumption changes related to Federal and State benefit levels, and c) an immaterial correction to prior year assumptions of \$22.8 million in the fourth quarter of 2025 related to terminated employees. These favorable changes were partially offset by an unfavorable change in the discount rate and an adjustment based on a change in our employment demographics. The actuarial gain component of the change in benefit obligations in 2024 was primarily attributable to a) favorable changes in the discount rate, b) favorable demographics in the at-risk population, and c) favorable assumption changes related to Federal and State benefit levels. These favorable changes were partially offset by unfavorable assumption changes regarding future average medical benefits and adjustment based on a change in our employment demographics.

Summarized below is information about the amounts recognized in the accompanying consolidated balance sheets for pneumoconiosis and workers' compensation benefits:

	December 31,	
	2025	2024
	(in thousands)	
Workers' compensation claims	\$ 49,378	\$ 47,870
Pneumoconiosis benefit claims	105,005	124,297
Total obligations	154,383	172,167
Less current portion	(15,901)	(14,838)
Non-current obligations	\$ 138,482	\$ 157,329

Both the pneumoconiosis benefit and workers' compensation obligations were unfunded at December 31, 2025 and 2024.

The pneumoconiosis benefit and workers' compensation expense consists of the following components:

	Year Ended December 31,		
	2025	2024	2023
		(in thousands)	
Service cost	\$ 3,471	\$ 3,443	\$ 2,698
Interest cost (1)	6,705	6,231	4,951
Net amortization (1)	928	3,356	1,382
Total pneumoconiosis expense	11,104	13,030	9,031
Workers' compensation expense	18,419	18,155	15,152
Net periodic benefit cost	\$ 29,523	\$ 31,185	\$ 24,183

(1) Interest cost and net amortization is included in the *Other income* line item within our consolidated statements of income.

14. EMPLOYEE BENEFIT PLANS

Defined Contribution Plans

All regular full-time employees are eligible to participate in a defined contribution profit sharing and savings plan ("PSSP") that we sponsor. PSSP participants may elect to make voluntary contributions to this plan up to a specified amount of their compensation. We make matching contributions based on a percentage of an employee's eligible compensation and also make an additional non-matching contribution. Our contribution expense for the PSSP was \$23.7 million, \$25.5 million and \$21.8 million for the years ended December 31, 2025, 2024 and 2023, respectively.

Defined Benefit Plan

Eligible employees and former employees of certain of our mining operations participate in a defined benefit plan (the "Pension Plan") that we sponsor. The Pension Plan is closed to new applicants. Participants in the Pension Plan are no longer receiving benefit accruals for service. The benefit formula for the Pension Plan is a fixed-dollar unit based on years of service.

The following sets forth changes in benefit obligations and plan assets for the years ended December 31, 2025 and 2024 and the funded status of the Pension Plan reconciled with the amounts reported in our consolidated financial statements:

	December 31,	
	2025	2024
	(dollars in thousands)	
Change in benefit obligations:		
Benefit obligations at beginning of year	\$ 98,977	\$ 105,870
Interest cost	5,242	5,107
Actuarial gain	(1,806)	(4,509)
Benefits paid	(6,374)	(7,491)
Benefit obligations at end of year	<u>96,039</u>	<u>98,977</u>
Change in plan assets:		
Fair value of plan assets at beginning of year	100,942	97,252
Employer contribution	817	152
Actual return on plan assets	12,388	11,029
Benefits paid	(6,374)	(7,491)
Fair value of plan assets at end of year	<u>107,773</u>	<u>100,942</u>
Funded status at the end of year	<u>\$ 11,734</u>	<u>\$ 1,965</u>
Amounts recognized in balance sheet:		
Non-current assets	<u>\$ 11,734</u>	<u>\$ 1,965</u>
Amounts recognized in accumulated other comprehensive loss consists of:		
Prior service cost	\$ —	\$ (10)
Net actuarial gain (loss)	<u>4,656</u>	<u>(2,694)</u>
	<u>\$ 4,656</u>	<u>\$ (2,704)</u>
Weighted-average assumption to determine benefit obligations as of December 31,		
Discount rate	5.47%	5.51%
Weighted-average assumptions used to determine net periodic benefit cost for the year ended December 31,		
Discount rate	5.51%	4.90%
Expected return on plan assets	7.00%	7.50%

The actuarial gain component of the change in benefit obligations in 2025 was primarily attributable to the buy-in transaction as discussed in more detail below. The actuarial gain component of the change in benefit obligations in 2024 was primarily attributable to an increase in the discount rate compared to the prior year end.

The actual return on plan assets was 13.5% and 11.3% for the years ended December 31, 2025 and 2024, respectively.

	Year Ended December 31,		
	2025	2024	2023
	(in thousands)		
Components of net periodic benefit credit:			
Interest cost	\$ 5,242	\$ 5,107	\$ 5,180
Expected return on plan assets	(6,844)	(7,031)	(6,220)
Amortization of prior service cost	9	186	186
Amortization of net loss	—	383	682
Net periodic benefit credit (1)	<u>\$ (1,593)</u>	<u>\$ (1,355)</u>	<u>\$ (172)</u>

- (1) Nonservice components of net periodic benefit credit are included in the *Other income (expense)* line item within our consolidated statements of income.

	Year Ended December 31,	
	2025	2024
	(in thousands)	
Other changes in plan assets and benefit obligation recognized in accumulated other comprehensive loss:		
Net actuarial gain	\$ 7,351	\$ 8,507
Reversal of amortization item:		
Prior service cost	9	186
Net actuarial loss	—	383
Total recognized in accumulated other comprehensive loss	<u>7,360</u>	<u>9,076</u>
Net periodic benefit credit	<u>1,593</u>	<u>1,355</u>
Total recognized in net periodic benefit credit and accumulated other comprehensive loss	<u>\$ 8,953</u>	<u>\$ 10,431</u>

Estimated future benefit payments as of December 31, 2025 are as follows:

Year Ended December 31,	(in thousands)
2026	\$ 6,646
2027	6,771
2028	6,867
2029	6,972
2030	7,008
2031-2035	35,374
	<u>\$ 69,638</u>

We do not expect to make material contributions to the Pension Plan during 2026.

In December 2025, we entered into a pension buy-in transaction with an insurance carrier to secure pension benefits for plan participants. In connection with the buy-in the Pension Plan purchased a buy-in contract. The buy-in contract is accounted for as a plan asset as we retain the underlying pension obligation. Subsequent to the buy-in, we measure the pension obligation at an amount equal to the fair value of the buy-in contract, reflecting the rate at which the obligation could be effectively settled. Prior to the buy-in, we had appointed an investment manager, which employed an asset allocation strategy through investment in certain investment types such as equity securities and fixed income securities. The objective of the previous allocation policy was to achieve an average annual return greater than the actuarial discount rate over the specified time horizon.

The following information discloses the fair values of our Pension Plan assets by asset category:

	December 31,							
	2025				2024			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(in thousands)							
Cash and cash equivalents	\$ 2,509	\$ —	\$ —	\$ 2,509	\$ 2,243	\$ —	\$ —	\$ 2,243
Equity investments - Individual securities								
(a):								
Consumer discretionary	—	—	—	—	3,572	—	—	3,572
Consumer durables	—	—	—	—	2,257	—	—	2,257
Energy	—	—	—	—	1,046	—	—	1,046
Financials	—	—	—	—	5,302	—	—	5,302
Health Care	—	—	—	—	3,972	—	—	3,972
Industrials & materials	—	—	—	—	4,402	—	—	4,402
Information technology & communication	—	—	—	—	9,052	—	—	9,052
Fixed income - Investments (b):								
Preferred stocks non-convertible	—	—	—	—	14	—	—	14
Real return mutual funds	—	—	—	—	464	—	—	464
Exchange traded mutual funds	—	—	—	—	591	—	—	591
Equity investments - Mutual funds (c):								
Mid-cap stock funds	—	—	—	—	11,327	—	—	11,327
Small-cap stock funds	—	—	—	—	3,316	—	—	3,316
International stock funds	—	—	—	—	4,689	—	—	4,689
Equity investments - Exchange traded funds (d):								
Large-cap blend - S&P 500 index	—	—	—	—	20,144	—	—	20,144
International - Developed markets	—	—	—	—	3,126	—	—	3,126
International - Emerging markets	—	—	—	—	3,338	—	—	3,338
Accrued income (e)	—	17	—	17	—	26	—	26
Buy-in contract (f)	—	—	96,039	96,039	—	—	—	—
	<u>\$ 2,509</u>	<u>\$ 17</u>	<u>\$ 96,039</u>	<u>\$ 98,565</u>	<u>\$ 78,855</u>	<u>\$ 26</u>	<u>\$ —</u>	<u>\$ 78,881</u>
Commingled investment funds measured at net asset value (g):								
Fixed income - Investment grade				9,208				22,061
Total				<u>\$ 107,773</u>				<u>\$ 100,942</u>

- (a) Equity investments - Individual securities include investments in publicly traded common stock and American Depositary Receipts. Publicly traded common stocks are traded on a national securities exchange and investments in common stocks are valued using quoted market prices multiplied by the number of shares owned. American Depositary Receipts are negotiable securities issued by a bank representing shares in a foreign company and traded on a national securities exchange.
- (b) Fixed income - investments include investments in preferred stock, mutual funds and exchange traded funds that are traded on a national securities exchange and valued using quoted market prices multiplied by the number of shares owned.
- (c) Equity investments - Mutual funds are valued daily in actively traded markets. For purposes of calculating the value, portfolio securities and other assets for which market quotes are readily available are valued at market value. Investments initially valued in currencies other than the U.S. dollars are converted to the U.S. dollar using exchange rates obtained from pricing services.
- (d) Equity investments – Exchange traded funds are funds that own financial assets and trade on exchanges, generally tracking a specific index. Investments in exchange traded funds are valued using a market approach based on the quoted market prices.
- (e) Accrued income represents dividends or interest declared, but not received, at the end of the period.

- (f) Buy-in contract – A contract that reimburses the Partnership for pension payments made to participants of the pension plan. The buy-in contract's fair value is determined using the quote provided by an insurance company, reflecting prevailing market conditions for similar transactions. The following table presents changes in the value of the buy-in contract, which represents our only plan asset valued using significant unobservable inputs.

	Year Ended December 31,
	2025
	(in thousands)
Beginning balance	\$ —
Purchase	96,577
Actual return on plan assets	(538)
Ending balance	<u>\$ 96,039</u>

- (g) Investments measured at fair value using the net asset value per share (or its equivalent) have not been classified within the fair value hierarchy. The fair values of all commingled investment funds are determined based on the net asset values per unit of each of the funds. The net asset values per unit represent the aggregate value of the fund's assets at fair value less liabilities, divided by the number of units outstanding.

15. ASSET RETIREMENT OBLIGATIONS

The following table presents the activity affecting our asset retirement and mine closing liability:

	Year Ended December 31,	
	2025	2024
	(in thousands)	
Beginning balance	\$ 158,777	\$ 150,443
Accretion expense	4,969	4,528
Payments	(1,937)	(1,770)
Allocation of liability associated with mine development and change in assumptions	(4,242)	5,576
Ending balance	<u>\$ 157,567</u>	<u>\$ 158,777</u>

The decrease in the allocation of liability associated with mine development and change in assumptions for the year ended December 31, 2025 was largely attributable to lower cost assumptions.

The increase in the allocation of liability associated with mine development and change in assumptions for the year ended December 31, 2024 was largely attributable to higher cost assumptions.

Estimated payments of asset retirement obligations are as follows:

Year Ended December 31,	(in thousands)
2026	\$ 4,320
2027	4,376
2028	3,152
2029	7,890
2030	3,467
Thereafter	246,703
Aggregate undiscounted asset retirement obligations	269,908
Less: effect of discounting	(112,341)
Total asset retirement obligations	157,567
Less: current portion	(4,320)
Non-current asset retirement obligations	<u>\$ 153,247</u>

As of December 31, 2025 and 2024, we had \$158.0 million and \$170.1 million, respectively, in surety bonds outstanding to secure the performance of our reclamation obligations.

16. COMMITMENTS AND CONTINGENCIES

Commitments

We lease buildings and equipment under operating lease agreements that provide for the payment of both minimum and contingent rentals. We also have noncancelable coal mineral reserve and resource leases as discussed in Note 21 – Related-Party Transactions. We have contractual commitments of \$94.3 million at December 31, 2025.

General Litigation

Certain of our subsidiaries were party to litigation in which the plaintiffs alleged violations of the Fair Labor Standards Act and state law due to alleged failure to compensate for time “donning” and “doffing” equipment and to account for certain bonuses in the calculation of overtime rates and pay. In April 2024, we entered into a settlement agreement with the plaintiffs to settle the litigation for \$15.3 million, which we accrued as of December 31, 2024. Our \$15.3 million accrual is included in the *Other current liabilities* line item on our consolidated balance sheet. In November 2025, the court approved the parties’ settlement and settlement checks were distributed in December 2025.

We also have various other lawsuits, claims and regulatory proceedings incidental to our business that are pending against us. We record an accrual for a potential loss related to these matters when, in management’s opinion, such loss is probable and reasonably estimable. Based on known facts and circumstances, we believe the ultimate outcome of these outstanding lawsuits, claims and regulatory proceedings will not have a material adverse effect on our financial condition, results of operations or liquidity. However, if the results of these matters are different from management’s current expectations and in amounts greater than our accruals, such matters could have a material adverse effect on our business and operations.

Other

Effective October 1, 2025, we renewed our property and casualty insurance program through September 30, 2026. Our property insurance was procured from our wholly owned captive insurance company, Wildcat Insurance, LLC (“Wildcat Insurance”). Wildcat Insurance charged certain of our subsidiaries for the premiums on this program and in return purchased reinsurance for the program in the standard market. The maximum limit in the commercial property program is \$100.0 million per occurrence, excluding a \$1.5 million deductible for property damage, a 75- or 90-day waiting period for underground business interruption depending on the mining complex and an additional \$25.0 million overall aggregate deductible. We retained a 2.50% participating interest in our current commercial property insurance program. We can make no assurances that we will not experience significant insurance claims in the future that could have a material adverse effect on our business, financial condition, results of operations and ability to purchase property insurance in the future. Also, exposures exist for which no insurance may be available and for which we have not reserved. In addition, the insurance industry has been subject to efforts by environmental activists to restrict coverages available for fossil-fuel companies.

17. PARTNERS’ CAPITAL

Distributions

Our available cash may, at the discretion of our general partner, be distributed within 45 days after the end of each quarter to unitholders of record. Available cash is generally defined in the partnership agreement as all cash and cash equivalents on hand at the end of each quarter less reserves established by MGP in its reasonable discretion for future cash requirements. These reserves are retained to provide for the conduct of our business, the payment of debt principal and interest and to provide funds for future distributions. The following table summarizes the quarterly per unit distribution paid during each quarter of 2023 through 2025:

	Year Ended December 31,		
	2025	2024	2023
First Quarter	\$ 0.700	\$ 0.700	\$ 0.700
Second Quarter	\$ 0.700	\$ 0.700	\$ 0.700
Third Quarter	\$ 0.600	\$ 0.700	\$ 0.700
Fourth Quarter	\$ 0.600	\$ 0.700	\$ 0.700

On January 27, 2026, we declared a quarterly distribution of \$0.60 per unit, totaling \$77.1 million, on all our common units outstanding, which was paid on February 13, 2026 to all unitholders of record on February 6, 2026.

Unit Repurchase Program

In January 2023, the board of directors of MGP authorized a \$93.5 million increase to the unit repurchase program, which had \$6.5 million of available capacity as of December 31, 2022. As a result, we were authorized to repurchase up to a total of \$100.0 million of ARLP common units. The program has no time limit and we may repurchase units from time to time in the open market or in other privately negotiated transactions. The unit repurchase program authorization does not obligate us to repurchase any dollar amount or number of units. No units were repurchased during the years ended December 31, 2025 and 2024. During the year ended December 31, 2023, we repurchased and retired 929,842 units at an average unit price of \$20.90 for an aggregate purchase price of \$19.4 million, leaving \$80.6 million remaining under the current authorization. Since inception of the unit repurchase program, we have repurchased and retired 6,390,446 units at an average unit price of \$17.67 for an aggregate purchase price of \$112.9 million.

Other

The noncontrolling interest in our consolidated balance sheets represents Bluegrass Minerals' ownership interest in Cavalier Minerals. Our accumulated other comprehensive loss primarily consists of unrecognized actuarial gains and losses as well as unrecognized prior service costs related to our pension and pneumoconiosis benefits. See Note 3 – Variable Interest Entities, Note 13 – Accrued Workers' Compensation and Pneumoconiosis Benefits and Note 14 – Employee Benefit Plans for further information.

18. COMMON UNIT-BASED COMPENSATION PLANS

Long-Term Incentive Plan

A summary of non-vested LTIP grants of restricted units is as follows:

	Number of units	Weighted average grant date fair value per unit	Intrinsic value (in thousands)
<i>Non-vested grants at January 1, 2023</i>	3,697,133	\$ 7.40	\$ 75,126
Granted (1)	450,125	21.54	
Vested (2)	(1,291,330)	5.02	
Forfeited	(145,584)	6.86	
<i>Non-vested grants at December 31, 2023</i>	2,710,344	10.91	57,405
Granted (1)	455,574	19.69	
Vested (2)	(1,582,422)	6.53	
Forfeited	(124,932)	20.37	
<i>Non-vested grants at December 31, 2024</i>	1,458,564	17.60	38,346
Granted (1)	376,853	26.92	
Vested (2)	(625,649)	13.62	
Forfeited	(17,525)	21.39	
<i>Non-vested grants at December 31, 2025</i>	1,192,243	22.58	27,696

(1) Restricted units granted have certain minimum-value guarantees per unit, regardless of whether the awards vest.

- (2) During the years ended December 31, 2025, 2024 and 2023, we issued 366,043, 936,544 and 860,060 unrestricted common units, respectively, to the LTIP participants. The remaining vested units were withheld to satisfy tax withholdings.

For the years ended December 31, 2025, 2024 and 2023, our LTIP expense for grants of restricted units was \$8.9 million, \$8.3 million and \$10.4 million, respectively. The total obligation associated with LTIP grants of restricted units as of December 31, 2025 and 2024 was \$17.2 million and \$16.9 million, respectively, and is included in the partners' capital *Limited partners-common unitholders* line item in our consolidated balance sheets. As of December 31, 2025, there was \$9.7 million in total unrecognized compensation expense related to the non-vested LTIP restricted unit grants that are expected to vest. That expense is expected to be recognized over a weighted-average period of 1.5 years.

On January 27, 2026, the Compensation Committee authorized additional grants of 410,443 restricted units, of which 395,443 units were granted. These restricted units have certain minimum-value guarantees, regardless of whether the awards vest.

Supplemental Executive Retirement Plan and Directors' Deferred Compensation Plan

A summary of SERP and Directors' Deferred Compensation Plan activity is as follows:

	<u>Number of units</u>	<u>Weighted average fair value per unit</u>	<u>Intrinsic value (in thousands)</u>
<i>Phantom units outstanding as of January 1, 2023</i>	742,540	\$ 20.28	\$ 15,088
Granted	118,737	20.46	
Settled (1)	(49,331)	20.27	
<i>Phantom units outstanding as of December 31, 2023</i>	811,946	20.44	17,197
Granted	100,757	22.85	
Settled (1) (2)	(912,703)	26.37	
<i>Phantom units outstanding as of December 31, 2024</i>	<u>—</u>		

- (1) During the years ended December 31, 2024 and 2023, we purchased 54,152 and 27,576 ARLP common units, respectively, on the open market to settle the accounts of participants under the SERP. Units purchased were net of units settled in cash to satisfy tax withholdings.
- (2) On December 16, 2024, the SERP and Directors' Deferred Compensation Plan were terminated, and final distributions of applicable plan accounts were settled in cash.

Total SERP and Directors' Deferred Compensation Plan expense was \$2.3 million and \$2.4 million for the years ended December 31, 2024 and 2023, respectively.

19. REVENUE FROM CONTRACTS WITH CUSTOMERS

The following table illustrates the disaggregation of our revenues by type, including a reconciliation to our segment presentation as presented in Note 25 – Segment Information.

	Coal Operations		Royalties		Other, Corporate and Elimination	Consolidated
	Illinois Basin	Appalachia	Oil & Gas	Coal		
	(in thousands)					
Year Ended December 31, 2025						
Coal sales	\$ 1,342,334	\$ 590,181	\$ —	\$ —	\$ —	\$ 1,932,515
Oil & gas royalties	—	—	137,849	—	—	137,849
Coal royalties	—	—	—	80,471	(80,471)	—
Transportation revenues	24,967	11,645	—	—	—	36,612
Other revenues	8,861	2,877	1,707	—	74,390	87,835
Total revenues	<u>\$ 1,376,162</u>	<u>\$ 604,703</u>	<u>\$ 139,556</u>	<u>\$ 80,471</u>	<u>\$ (6,081)</u>	<u>\$ 2,194,811</u>
Year Ended December 31, 2024						
Coal sales	\$ 1,399,100	\$ 712,703	\$ —	\$ —	\$ —	\$ 2,111,803
Oil & gas royalties	—	—	138,311	—	—	138,311
Coal royalties	—	—	—	69,676	(69,676)	—
Transportation revenues	85,142	27,448	—	—	—	112,590
Other revenues	11,901	3,091	825	65	70,122	86,004
Total revenues	<u>\$ 1,496,143</u>	<u>\$ 743,242</u>	<u>\$ 139,136</u>	<u>\$ 69,741</u>	<u>\$ 446</u>	<u>\$ 2,448,708</u>
Year Ended December 31, 2023						
Coal sales	\$ 1,364,901	\$ 845,309	\$ —	\$ —	\$ —	\$ 2,210,210
Oil & gas royalties	—	—	137,751	—	—	137,751
Coal royalties	—	—	—	65,572	(65,572)	—
Transportation revenues	106,150	36,140	—	—	—	142,290
Other revenues	10,505	1,885	3,774	42	60,244	76,450
Total revenues	<u>\$ 1,481,556</u>	<u>\$ 883,334</u>	<u>\$ 141,525</u>	<u>\$ 65,614</u>	<u>\$ (5,328)</u>	<u>\$ 2,566,701</u>

The following table illustrates the beginning and ending balances of our trade receivables:

	Year Ended December 31,		
	2025	2024	2023
	(in thousands)		
Beginning balance	\$ 166,829	\$ 282,622	\$ 241,412
Ending balance	\$ 129,686	\$ 166,829	\$ 282,622

The following table illustrates the projected revenue for all coal supply contracts allocated to performance obligations that are unsatisfied or partially unsatisfied as of December 31, 2025 and disaggregated by segment and contract duration.

	2026	2027	2028	2029 and Thereafter	Total
	(in thousands)				
Illinois Basin Coal Operations coal revenues	\$ 1,199,480	\$ 770,364	\$ 453,259	\$ 310,474	\$ 2,733,577
Appalachia Coal Operations coal revenues	449,944	298,139	236,920	18,000	1,003,003
Total coal revenues	<u>\$ 1,649,424</u>	<u>\$ 1,068,503</u>	<u>\$ 690,179</u>	<u>\$ 328,474</u>	<u>\$ 3,736,580</u>

20. CONCENTRATION OF CREDIT RISK AND MAJOR CUSTOMERS

The international coal market has been a part of our business with indirect sales to end-users in Europe, Africa, Asia, North America and South America. Our sales into the international coal market are considered exports and are made through brokered transactions. During the years ended December 31, 2025, 2024 and 2023, export tons represented approximately 8.6%, 17.3% and 15.7% of tons sold, respectively.

Because title to our export shipments typically transfers to our brokerage customers at a point that does not necessarily reflect the end-usage point, we attribute export tons to the country with the end-usage point, if known. No individual country was attributed greater than 10% of all tons sold during the years ended December 31, 2025, 2024 and 2023.

We have significant long-term coal supply agreements, some of which contain prospective price adjustment provisions designed to reflect changes in market conditions, labor and other production costs and, in the infrequent circumstance when the coal is sold other than free on board the mine, changes in transportation rates. A major customer is defined as a customer from which we derive at least 10% of our total revenues, including transportation revenues. Total revenues from major customers are as follows:

Segment		Year Ended December 31,		
		2025	2024	2023
		(in thousands)		
Customer A	Illinois Basin	\$ 344,852	270,448	—
Customer B	Illinois Basin/Appalachia	327,759	\$ 422,936	\$ 332,500
Customer C	Illinois Basin	—	241,800	253,573

Trade accounts receivable from major customers totaled \$25.3 million and \$50.1 million at December 31, 2025 and 2024, respectively. Our credit loss experience has historically been insignificant. Financial conditions of our customers could result in a material change to our credit loss expense in future periods. The coal supply agreements with Customers A and B expire in 2030 and 2028, respectively.

21. RELATED-PARTY TRANSACTIONS

We have continuing related-party transactions with MGP and its affiliates. The board of directors of our general partner (“Board of Directors”) and its conflicts committee (“Conflicts Committee”) review our related-party transactions that involve a potential conflict of interest between our general partner or its affiliates and ARLP or its subsidiaries or any other partner of ARLP to determine that such transactions are fair and reasonable to ARLP. As a result of these reviews, the Board of Directors and the Conflicts Committee approved each of the transactions described below that had such potential conflict of interest as fair and reasonable to ARLP.

Affiliate Coal Lease Agreements

The following table summarizes advanced royalties outstanding and related payments and recoupments under our affiliate coal lease agreements:

	Craft Foundations	WKY CoalPlay			Total
		Towhead Coal	Henderson Coal	WKY CoalPlay	
		Henderson & Union Counties, KY	Henderson County, KY	Henderson & Union Counties, KY	
	Tunnel Ridge				
	Acquired 2005	Acquired 2014	Acquired 2014	Acquired 2015	
<i>(in thousands)</i>					
As of January 1, 2023	\$ 1,500	\$ 22,092	\$ 20,172	\$ 16,844	\$ 60,608
Payments	3,000	3,597	2,521	2,131	11,249
Recoupment	(3,000)	(4,258)	—	—	(7,258)
Unrecoupable	—	—	—	—	—
As of December 31, 2023	1,500	21,431	22,693	18,975	64,599
Payments	3,000	3,597	2,521	2,131	11,249
Recoupment	(3,000)	(5,380)	(258)	(21)	(8,659)
Unrecoupable	—	—	—	—	—
As of December 31, 2024	1,500	19,648	24,956	21,085	67,189
Payments	1,500	3,597	2,521	2,131	9,749
Recoupment	(3,000)	(1,484)	(232)	(3,096)	(7,812)
Unrecoupable	—	—	—	—	—
As of December 31, 2025	\$ —	\$ 21,761	\$ 27,245	\$ 20,120	\$ 69,126

Craft Foundations

In January 2005, we acquired Tunnel Ridge from ARH. In connection with this acquisition, we assumed a coal lease and surface land lease with Alliance Resource GP, LLC, an entity indirectly wholly owned by Mr. Craft and Kathleen S. Craft until it was dissolved in December 2020. In December 2018, the property subject to the leases was transferred to The Joseph W. Craft III Foundation and The Kathleen S. Craft Foundation (the “Craft Foundations”). Under the terms of the coal lease, Tunnel Ridge is required to pay an annual minimum royalty of \$3.0 million. Tunnel Ridge incurred \$4.9 million, \$12.4 million and \$15.1 million in earned royalties under the coal lease in 2025, 2024 and 2023 respectively. The surface land lease has a \$0.2 million annual payment payable in January of each year.

On January 29, 2026, Alliance Resource Properties purchased all of the ownership interests in coal reserves together with surface rights located in Ohio County, West Virginia and Washington County, Pennsylvania subject to the leases from the Craft Foundations for \$15.5 million in the aggregate. The entire purchase price of \$7.75 million payable to The Kathleen S. Craft Foundation was paid in full at the closing, while The Joseph W. Craft III Foundation was paid approximately \$1.8 million at closing with the balance of the purchase price to be paid over the next six years. See Note 12 – Long-Term Debt for more information on the installment purchase arrangement.

WKY CoalPlay

In February 2015, WKY CoalPlay, LLC (“WKY CoalPlay”), an entity owned by the Craft Foundations and two limited liability companies owned by irrevocable trusts established by Mr. Craft and his children, entered into a coal lease agreement with Alliance Resource Properties regarding coal mineral resources located in Henderson and Union Counties, Kentucky. The lease has an initial term of 20 years and provides for earned royalty payments to WKY CoalPlay of 4.0% of the coal sales price and annual minimum royalty payments of \$2.1 million. All annual minimum royalty payments are recoupable from future earned royalties.

In December 2014, WKY CoalPlay’s subsidiaries, Towhead Coal Reserves, LLC and Henderson Coal Reserves, LLC entered into coal lease agreements with Alliance Resource Properties. The leases have initial terms of 20 years and provide

for earned royalty payments of 4.0% of the coal sales price and annual minimum royalty payments of \$3.6 million and \$2.5 million, respectively. All annual minimum royalty payments under each agreement are recoupable from future earned royalties payable under that agreement.

22. INCOME TAXES

Components of income before income taxes were attributable to the following categories:

	Year Ended December 31,		
	2025	2024	2023
	(in thousands)		
Domestic	\$ 335,450	\$ 381,494	\$ 644,450
Foreign	565	—	—
Total income before income taxes	<u>\$ 336,015</u>	<u>\$ 381,494</u>	<u>\$ 644,450</u>

Components of income tax expense disaggregated by jurisdiction are as follows:

	Year Ended December 31,		
	2025	2024	2023
	(in thousands)		
Current:			
Federal	\$ 17,952	\$ 16,719	\$ 15,917
State	1,541	1,403	1,336
Foreign	156	—	—
	<u>19,649</u>	<u>18,122</u>	<u>17,253</u>
Deferred:			
Federal	(587)	(2,104)	(7,235)
State	(297)	(81)	(1,738)
	<u>(884)</u>	<u>(2,185)</u>	<u>(8,973)</u>
Income tax expense	<u>\$ 18,765</u>	<u>\$ 15,937</u>	<u>\$ 8,280</u>

Reconciliations of income taxes at the U.S. federal statutory tax rate to income taxes at our effective tax rate are as follows:

	Year Ended December 31, 2025	
	Amount	Rate
	(in thousands)	
U.S. federal statutory income tax rate	\$ 70,563	21.0%
State and local income tax, net of federal income tax benefit (1)	983	0.3%
Foreign tax effects	38	0.0%
Tax credits	(602)	(0.2)%
Nontaxable or nondeductible items:		
Partnership income not subject to income taxes	(50,423)	(15.0)%
Noncontrolling interest income not subject to income taxes	(1,367)	(0.4)%
Other adjustments	(427)	(0.1)%
Income tax expense	<u>\$ 18,765</u>	<u>5.6%</u>

(1) State taxes in Texas and Oklahoma made up the majority of the tax effect in this category for 2025.

The effective income tax rate for our income tax expense for the years ended December 31, 2025 is less than the federal statutory rate, primarily due to the portion of income not subject to income tax.

	Year Ended December 31,	
	2024	2023
	(in thousands)	
Income taxes at statutory rate	\$ 80,114	\$ 135,335
Less: Income taxes at statutory rate on Partnership income not subject to income taxes	(61,619)	(119,556)
Increase (decrease) resulting from:		
State taxes, net of federal income tax	1,187	864
Tax effect of noncontrolling interest income not subject to income taxes	(1,058)	(1,361)
Return to accrual adjustments	(3,018)	(7,008)
Other	331	6
Income tax expense	<u>\$ 15,937</u>	<u>\$ 8,280</u>

The effective income tax rates for our income tax expense for the years ended December 31, 2024 and 2023 are less than the federal statutory rate, primarily due to the portion of income not subject to income taxes.

Significant components of deferred tax liabilities and deferred tax assets are as follows:

	December 31,	
	2025	2024
	(in thousands)	
Deferred tax liabilities:		
Property, plant and equipment	\$ (30,513)	\$ (33,168)
Digital assets	(3,233)	(4,319)
Equity investments	(6,270)	(1,240)
Other	(29)	(28)
Total deferred tax liabilities	(40,045)	(38,755)
Deferred tax assets:		
Federal loss carryovers and credits	10,604	9,016
State loss carryovers and credits	3,738	3,122
Capitalized research and development	2,590	2,646
Other	28	2
Total deferred tax assets	16,960	14,786
Overall net deferred tax liabilities	<u>\$ (23,085)</u>	<u>\$ (23,969)</u>

Deferred tax liabilities for property, plant and equipment are primarily the result of the Alliance Minerals' election in 2022 to change its federal income tax status from a pass-through entity to a taxable entity and a non-cash acquisition gain recognized in 2019 related to the acquisition of AllDale I & II. Deferred tax liabilities for digital assets are due to the remeasurement of our digital assets to fair value, which is not taxable until the digital asset is sold. Deferred tax liabilities for equity investments are due to differences between the financial reporting and tax bases of equity investments of other subsidiaries that are taxable for federal income tax purposes.

Federal and state loss carryovers and credits are primarily due to net operating losses and research and development credits associated with the operations of other subsidiaries that are taxable for federal income tax purposes. Research and development expenses from prior years were required to be capitalized and amortized for U.S. tax purposes, resulting in a deferred tax asset. These expenses are primarily associated with the operations of other subsidiaries that are taxable for federal income tax purposes. Deferred tax assets for federal loss carryovers and credits generally do not have an expiration date. Deferred tax assets for state loss carryovers and credits generally expire between 2028 and 2038 with some carryovers having indefinite carryforward periods.

The following table summarizes income taxes paid (net of refunds received) by jurisdiction:

	Year Ended December 31,		
	2025	2024	2023
	(in thousands)		
Federal	\$ 17,512	\$ 17,436	\$ 12,550
State	1,502	2,104	1,065
Foreign	71	—	—
Total income tax paid	\$ 19,085	\$ 19,540	\$ 13,615

Our 2020 through 2024 tax years remain open to examination by tax authorities, and lower-tier partnership income tax returns for the tax years ended December 31, 2020 and 2021 are being audited by the Internal Revenue Service.

23. EARNINGS PER LIMITED PARTNER UNIT

We utilize the two-class method in calculating basic and diluted earnings per limited partner unit (“EPU”). Subsequent to the JC Resources Acquisition, net income attributable to ARLP is allocated to limited partners and participating securities with nonforfeitable distributions or distribution equivalents, while net losses attributable to ARLP are allocated only to limited partners but not to participating securities. Prior to the JC Resources Acquisition, in addition to limited partners and participating securities allocations, amounts were also allocated to our general partner for historical earnings from the mineral interests acquired in the JC Resources Acquisition. Participating securities represent outstanding restricted unit awards under our LTIP. During 2024 and 2023, our participating securities also included phantom units in notional accounts under our SERP and Directors’ Deferred Compensation Plan. The SERP and Directors’ Deferred Compensation Plan were terminated and settled in December 2024 and no longer have participating securities that receive an allocation of income.

The following is a reconciliation of net income attributable to ARLP used for calculating basic and diluted earnings per unit and the weighted-average units used in computing EPU.

	Year Ended December 31,		
	2025	2024	2023
	(in thousands, except per unit data)		
Net income attributable to ARLP	\$ 311,163	\$ 360,855	\$ 630,118
Less:			
General partner's interest in net income attributable to ARLP	—	—	(1,384)
Limited partners' interest in net income attributable to ARLP	311,163	360,855	628,734
Less:			
Distributions to participating securities	(2,975)	(6,005)	(9,688)
Undistributed earnings attributable to participating securities	—	—	(7,203)
Net income attributable to ARLP available to limited partners	\$ 308,188	\$ 354,850	\$ 611,843
Weighted-average limited partner units outstanding – basic and diluted	128,388	127,965	127,180
Earnings per limited partner unit - basic and diluted (1)	\$ 2.40	\$ 2.77	\$ 4.81

- (1) Diluted EPU gives effect to all potentially dilutive common units outstanding during the period using the treasury stock method. Diluted EPU excludes all potentially dilutive units calculated under the treasury stock method if their effect is anti-dilutive. For the years ended December 31, 2025, 2024 and 2023, participating securities of 719, 1,889 and 2,922, respectively, were considered anti-dilutive under the treasury stock method.

24. SUPPLEMENTAL CASH FLOW INFORMATION

	Year Ended December 31,		
	2025	2024	2023
	(in thousands)		
Cash Paid For:			
Interest	\$ 45,613	\$ 44,834	\$ 37,126
Non-Cash Activity:			
Accounts payable for purchase of property, plant and equipment	\$ 12,902	\$ 23,728	\$ 14,586
Market value of common units distributed under deferred compensation plans before tax withholding requirements	\$ 17,068	\$ 34,880	\$ 28,906

25. SEGMENT INFORMATION

We operate in the United States as a diversified natural resource company that generates operating and royalty income from the production and marketing of coal to major domestic utilities, industrial users and international customers as well as royalty income from oil & gas mineral interests located in key producing regions across the United States. We aggregate multiple operating segments into four reportable segments, Illinois Basin Coal Operations, Appalachia Coal Operations, Oil & Gas Royalties and Coal Royalties. We also have an “all other” category referred to as Other, Corporate and Elimination. Our two coal operations reportable segments correspond to major coal producing regions in the eastern United States with similar economic characteristics including coal quality, geology, coal marketing opportunities, mining and transportation methods and regulatory issues. The two coal operations reportable segments include seven mining complexes operating in Illinois, Indiana, Kentucky, Maryland, Pennsylvania, and West Virginia and a coal loading terminal on the Ohio River in Indiana. Our Oil & Gas Royalties reportable segment includes our oil & gas mineral interests which are located primarily in the Permian (Delaware and Midland), Anadarko (SCOOP/STACK) and Williston (Bakken) basins. The operations within our Oil & Gas Royalties reportable segment primarily include receiving royalties and lease bonuses for our oil & gas mineral interests. Our Coal Royalties reportable segment includes coal mineral reserves and resources owned or leased by Alliance Resource Properties, which are either (a) leased to our mining complexes or (b) near our coal mining operations but not yet leased.

The Illinois Basin Coal Operations reportable segment includes (a) the Gibson County Coal, LLC’s mining complex, (b) the Warrior Coal, LLC mining complex, (c) the River View mining complex, which includes the River View and Henderson County mines and, (d) the Hamilton mining complex. The segment also includes activity associated with support services and our non-operating mining complexes.

The Appalachia Coal Operations reportable segment includes (a) the Mettiki mining complex, (b) the Tunnel Ridge mining complex and, (c) the MC Mining mining complex.

The Oil & Gas Royalties reportable segment includes oil & gas mineral interests held by Alliance Minerals’ through its consolidated subsidiaries as well as equity interests held in AllDale III (Note 3 – Variable Interest Entities).

The Coal Royalties reportable segment includes coal mineral reserves and resources owned or leased by Alliance Resource Properties that are (a) leased to certain of our mining complexes in the Illinois Basin and Appalachia Basin or (b) located near our operations and external mining operations.

Other, Corporate and Elimination includes marketing and administrative activities, Alliance Design and Alliance Service, Inc., including its subsidiaries (collectively, the “Matrix Group”), Bitiki KY, LLC (which holds our crypto-mining activities) (see Note 7 – Digital Assets), our non oil & gas equity investments (see Note 3 – Variable Interest Entities and Note 10 – Investments), Wildcat Insurance (which assists the ARLP Partnership with its insurance requirements), and AROP Funding and Alliance Finance (both discussed in Note 12 – Long-Term Debt). The eliminations included in Other, Corporate and Elimination primarily represent the intercompany coal royalty transactions described above between our Coal Royalties reportable segment and our coal operations’ mines.

Reportable segment results are presented below.

	Coal Operations		Royalties		
	Illinois Basin	Appalachia	Oil & Gas (in thousands)	Coal	Total
Year Ended December 31, 2025					
Revenues - Outside	\$ 1,376,162	\$ 604,703	\$ 139,556	\$ —	\$ 2,120,421
Revenues - Intercompany	—	—	—	80,471	80,471
Total revenues (1)	1,376,162	604,703	139,556	80,471	2,200,892
Less:					
Segment Adjusted EBITDA Expense (2)	894,521	459,351	18,447	27,612	1,399,931
Transportation expenses	24,967	11,645	—	—	36,612
Other segment items (3)	—	—	3,581	—	3,581
Segment Adjusted EBITDA (4)	456,674	133,707	117,528	52,859	760,768
Total assets (5)	1,030,398	445,327	878,668	297,714	2,652,107
Capital expenditures (6)	183,583	71,159	—	312	255,054
Year Ended December 31, 2024					
Revenues - Outside	\$ 1,496,143	\$ 743,242	\$ 139,136	\$ 65	\$ 2,378,586
Revenues - Intercompany	—	—	—	69,676	69,676
Total revenues (1)	1,496,143	743,242	139,136	69,741	2,448,262
Less:					
Segment Adjusted EBITDA Expense (2)	937,083	551,734	19,853	25,759	1,534,429
Transportation expenses	85,142	27,448	—	—	112,590
Other segment items (3)	—	—	2,325	—	2,325
Segment Adjusted EBITDA (4)	473,918	164,060	116,958	43,982	798,918
Total assets (5)	1,028,622	467,463	818,502	307,924	2,622,511
Capital expenditures (6)	301,591	109,315	—	—	410,906
Year Ended December 31, 2023					
Revenues - Outside	\$ 1,481,556	\$ 883,334	\$ 141,525	\$ 42	\$ 2,506,457
Revenues - Intercompany	—	—	—	65,572	65,572
Total revenues (1)	1,481,556	883,334	141,525	65,614	2,572,029
Less:					
Segment Adjusted EBITDA Expense (2)	861,288	516,471	16,532	24,451	1,418,742
Transportation expenses	106,150	36,140	—	—	142,290
Other segment items (3)	—	—	3,485	—	3,485
Segment Adjusted EBITDA (4)	514,118	330,723	121,508	41,163	1,007,512
Total assets (5)	966,102	488,427	781,184	315,592	2,551,305
Capital expenditures (6)	257,885	116,217	—	400	374,502

(1) The following is a reconciliation of our total segment revenues to total consolidated revenues:

	Year Ended December 31,		
	2025	2024	2023
	(in thousands)		
Total segment revenues	\$ 2,200,892	\$ 2,448,262	\$ 2,572,029
Other, Corporate and Elimination revenues - Outside	74,390	70,122	60,244
Other, Corporate and Elimination revenues - Intercompany	(80,471)	(69,676)	(65,572)
Total consolidated revenues	\$ 2,194,811	\$ 2,448,708	\$ 2,566,701

Revenues included in Other, Corporate and Elimination are attributable to intercompany eliminations, which are primarily intercompany coal royalties eliminations, outside revenues at the Matrix Group and other outside miscellaneous sales and revenue activities.

- (2) Segment Adjusted EBITDA Expense includes operating expenses, coal purchases, if applicable, and other income or expense as adjusted to remove certain items from operating expenses that we characterize as unrepresentative of our ongoing operations. Segment Adjusted EBITDA Expense is used as a financial measure by our management to assess the operating performance of our segments. Segment Adjusted EBITDA Expense is a key component of Segment Adjusted EBITDA in addition to coal sales, royalty revenues and other revenues. The exclusion of corporate general and administrative expenses from Segment Adjusted EBITDA Expense allows management to focus solely on the evaluation of segment operating performance as it primarily relates to our operating expenses.
- (3) Other segment items include:
Oil & Gas Royalties – equity method investment income from AllDale III and income allocated to noncontrolling interest
- (4) Segment Adjusted EBITDA is defined as net income attributable to ARLP before net interest expense, income taxes, depreciation, depletion and amortization and general and administrative expenses adjusted for certain items that we characterize as unrepresentative of our ongoing operations. Segment Adjusted EBITDA is used as a financial measure by Mr. Craft, who is also our chief operating decision maker (“CODM”), other management and by external users of our financial statements such as investors, commercial banks, research analysts and others. Our CODM uses Segment Adjusted EBITDA in assessing segment performance and deciding how to allocate resources. Segment Adjusted EBITDA provides useful information to our CODM and investors regarding our performance and results of operations because Segment Adjusted EBITDA (i) provides additional information about our core operating performance and ability to generate and distribute cash flow, (ii) provides investors with the financial analytical framework upon which we base financial, operational, compensation and planning decisions, (iii) presents a measurement that investors, rating agencies and debt holders have indicated is useful in assessing us and our results of operations and (iv) allows our CODM and management to focus solely on the evaluation of segment operating profitability as it relates to our revenues and operating expenses, which are primarily controlled by our segments.

The following is a reconciliation of total Segment Adjusted EBITDA for our segments to consolidated income before income taxes:

	Year Ended December 31,		
	2025	2024	2023
	(in thousands)		
Segment Adjusted EBITDA – total segments	\$ 760,768	\$ 798,918	\$ 1,007,512
Other, Corporate and Elimination profit (loss)	21,090	(2,464)	4,661
General and administrative	(83,119)	(82,224)	(79,096)
Depreciation, depletion and amortization	(299,436)	(285,446)	(267,982)
Asset Impairments	—	(31,130)	—
Interest expense, net	(36,984)	(28,007)	(26,697)
Change in fair value of digital assets	(4,354)	22,395	—
Impairment loss on investments	(28,037)	—	—
Litigation expense accrual	—	(15,250)	—
Noncontrolling interest	6,087	4,702	6,052
Income before income taxes	<u>\$ 336,015</u>	<u>\$ 381,494</u>	<u>\$ 644,450</u>

Other, Corporate and Elimination profit (loss) represents profit (loss) from operating segments below the quantitative thresholds when determining our reportable segments as well as the elimination of intersegment profit (loss) between our reportable segments. The operating segments included are those described as part of our Other, Corporate and Eliminations category.

(5) The following is a reconciliation of our total segment assets to total consolidated assets:

	December 31,		
	2025	2024	2023
	(in thousands)		
Total segment assets	\$ 2,652,107	\$ 2,622,511	\$ 2,551,305
Other, Corporate and Elimination total assets	201,681	293,219	237,121
Total consolidated assets	<u>\$ 2,853,788</u>	<u>\$ 2,915,730</u>	<u>\$ 2,788,426</u>

(6) Capital expenditures shown exclude \$17.8 million, \$24.7 million and \$110.9 million paid for oil & gas acquisitions in 2025, 2024 and 2023, respectively. See Note 4 – Acquisitions for more information. The following is a reconciliation of our total segment capital expenditures to total consolidated capital expenditures:

	Year Ended December 31,		
	2025	2024	2023
	(in thousands)		
Total segment capital expenditures	\$ 255,054	\$ 410,906	\$ 374,502
Other, Corporate and Elimination capital expenditures	8,226	17,835	4,836
Total consolidated capital expenditures	<u>\$ 263,280</u>	<u>\$ 428,741</u>	<u>\$ 379,338</u>

26. SUBSEQUENT EVENT

On January 29, 2026, we announced our decision to cease longwall production at our Mettiki mining complex and primarily satisfy remaining contracted commitments from existing inventory. We will continue to evaluate options concerning the mine's future. We are in the process of determining the fair value of the assets at Mettiki and estimate that there could be an impairment charge of up to approximately \$43.0 million in the first quarter of 2026 primarily in our Appalachia reportable segment.

SUPPLEMENTAL OIL & GAS RESERVE INFORMATION (UNAUDITED)

Geographical Area of Operation

All of our proved oil & gas reserves are located within the continental United States with the majority concentrated in Texas, Oklahoma, New Mexico and North Dakota. The following supplemental disclosures about our proved oil & gas reserves including costs incurred, capitalized cost, results of operations and cash flows are presented on a consolidated basis.

Costs Incurred in Oil & Gas Property Acquisitions

Costs incurred in oil & gas property acquisitions are presented below:

	Year Ended December 31,		
	2025	2024	2023
	(in thousands)		
Acquisition costs of properties			
Proved	\$ 11,484	\$ 7,093	\$ 21,943
Unproved	6,353	17,640	16,741
Total	<u>\$ 17,837</u>	<u>\$ 24,733</u>	<u>\$ 38,684</u>

Property acquisition costs for 2025 primarily include the Elk Range Acquisition and other ground game acquisitions. Property acquisition costs for 2024 primarily include other ground game acquisitions. Property acquisition costs for 2023 primarily include the Skyland Acquisition and other ground game acquisitions. See Note 4 – Acquisitions in our consolidated financial statements for more information regarding these acquisitions.

Oil & Gas Capitalized Costs

Aggregate capitalized costs related to oil & gas activities with applicable accumulated depreciation, depletion, and amortization are presented below:

	As of December 31,					
	2025		2024		2023	
	(in thousands)					
	Our Share of an Equity Method		Our Share of an Equity Method		Our Share of an Equity Method	
	Consolidated	Investee	Consolidated	Investee	Consolidated	Investee
Proved properties	\$ 531,892	\$ 18,180	\$ 497,252	\$ 17,031	\$ 438,378	\$ 14,950
Unproved properties	364,028	9,949	380,831	11,127	414,972	13,295
Total	895,920	28,129	878,083	28,158	853,350	28,245
Less accumulated depreciation, depletion and amortization	(220,918)	(7,890)	(184,365)	(6,469)	(144,561)	(5,183)
Oil & gas properties, net	\$ 675,002	\$ 20,239	\$ 693,718	\$ 21,689	\$ 708,789	\$ 23,062

Results of Operations from Oil & Gas Activities

The following schedule sets forth the revenues and expenses related to our oil & gas mineral interests. It does not include any interest costs or general and administrative costs, and therefore, is not necessarily indicative of the contribution of our Oil & Gas Royalties segment to our overall results.

	Year Ended December 31,		
	2025	2024	2023
	(in thousands)		
Consolidated activities			
Oil & gas royalties	\$ 137,849	\$ 138,311	\$ 137,751
Other revenues	1,707	825	3,774
Production costs and severance taxes	(13,886)	(14,476)	(13,423)
Depreciation, depletion and amortization	(36,553)	(39,804)	(36,865)
Income tax expense	(18,016)	(13,948)	(14,568)
Total results of oil & gas activities	<u>\$ 71,101</u>	<u>\$ 70,908</u>	<u>\$ 76,669</u>
Our share of an equity method investee			
Oil & gas royalties	\$ 5,212	\$ 4,535	\$ 4,719
Other revenues	38	31	102
Production costs and severance taxes	(704)	(630)	(638)
Depreciation, depletion and amortization	(1,221)	(1,206)	(1,142)
Total results of oil & gas activities	<u>\$ 3,325</u>	<u>\$ 2,730</u>	<u>\$ 3,041</u>

Oil & Gas Reserves

The net proved developed and undeveloped oil & gas reserves quantities of the mineral interests attributable to us are summarized below:

	Crude Oil (MBbl)	Natural Gas (MMcf)	Natural Gas Liquids (MBbl)	Total (MBOE)
<i>Consolidated activities</i>				
As of January 1, 2023	9,013	45,322	5,476	22,043
Purchases of minerals in place	361	2,421	142	907
Revisions of previous estimates	(175)	2,177	559	748
Extensions and discoveries	1,252	4,460	654	2,649
Production	<u>(1,418)</u>	<u>(5,759)</u>	<u>(726)</u>	<u>(3,105)</u>
As of December 31, 2023 (1)	9,033	48,621	6,105	23,242
Purchases of minerals in place	209	1,083	176	565
Revisions of previous estimates	(353)	1,175	299	142
Extensions and discoveries	1,859	8,399	1,164	4,423
Production	<u>(1,501)</u>	<u>(6,304)</u>	<u>(850)</u>	<u>(3,402)</u>
As of December 31, 2024 (1)	9,247	52,974	6,894	24,970
Purchases of minerals in place	280	949	153	591
Revisions of previous estimates	(897)	(2,012)	(317)	(1,550)
Extensions and discoveries	3,306	17,816	2,481	8,756
Production	<u>(1,628)</u>	<u>(6,674)</u>	<u>(908)</u>	<u>(3,648)</u>
As of December 31, 2025 (1)	<u>10,308</u>	<u>63,053</u>	<u>8,303</u>	<u>29,119</u>

(1) Proved reserves of approximately 2,037 MBOE, 1,879 MBOE and 1,780 MBOE were attributable to noncontrolling interests, as of December 31, 2025, 2024 and 2023, respectively.

	<u>Crude Oil (MBbl)</u>	<u>Natural Gas (MMcf)</u>	<u>Natural Gas Liquids (MBbl)</u>	<u>Total (MBOE)</u>
<i>Our share of an equity method investee</i>				
As of January 1, 2023	349	2,460	212	971
Sales of minerals in place	—	—	—	—
Revisions of previous estimates	(46)	74	(23)	(57)
Extensions and discoveries	61	770	59	248
Production	(44)	(402)	—	(110)
As of December 31, 2023	320	2,902	248	1,052
Sales of minerals in place	—	—	—	—
Revisions of previous estimates	(16)	54	(50)	(57)
Extensions and discoveries	74	544	51	216
Production	(42)	(454)	—	(118)
As of December 31, 2024	336	3,046	249	1,093
Sales of minerals in place	—	—	—	—
Revisions of previous estimates	(20)	(130)	(43)	(85)
Extensions and discoveries	22	510	11	118
Production	(49)	(423)	—	(120)
As of December 31, 2025	289	3,003	217	1,006
Total consolidated and equity interests in reserves at December 31, 2025	<u>10,597</u>	<u>66,056</u>	<u>8,520</u>	<u>30,125</u>

	<u>Crude Oil (MBbl)</u>	<u>Natural Gas (MMcf)</u>	<u>Natural Gas Liquids (MBbl)</u>	<u>Total (MBOE)</u>
<i>Consolidated activities</i>				
Net proved developed reserves as of				
January 1, 2023	7,320	39,083	4,638	18,472
December 31, 2023	7,489	43,167	5,276	19,960
December 31, 2024	8,053	48,420	6,221	22,343
December 31, 2025	8,909	57,940	7,563	26,128
Net proved undeveloped reserves as of				
January 1, 2023	1,692	6,240	839	3,571
December 31, 2023	1,544	5,454	829	3,282
December 31, 2024	1,194	4,554	673	2,626
December 31, 2025	1,399	5,113	740	2,991

<i>Our share of an equity method investee</i>	Crude Oil (MBbl)	Natural Gas (MMcf)	Natural Gas Liquids (MBbl)	Total (MBOE)
Net proved developed reserves as of				
January 1, 2023	231	2,090	168	747
December 31, 2023	265	2,517	209	894
December 31, 2024	248	2,668	194	888
December 31, 2025	250	2,793	191	906
Net proved undeveloped reserves as of				
January 1, 2023	119	369	43	224
December 31, 2023	55	385	39	158
December 31, 2024	88	378	55	206
December 31, 2025	39	210	26	100

Natural gas reserves are converted to BOE based on a 6:1 ratio: six Mcf of natural gas converts to one BOE.

Notable changes in proved reserves during the year ended December 31, 2023, included:

- *Net change due to extensions and discoveries* - The increases are a result of additional development by the operators of the properties under which we own mineral interests. In 2023, a net addition of 2,897 MBOE occurred primarily from the completion of 2,117 new wells on our acreage and from the addition of 548 new proved undeveloped locations due to permitting and drilling activity.
- *Revisions* - Increases in oil & gas reserves include 789 MBOE due to revisions of previous quantity estimates, offset by a decline of 98 MBOE due to changes in the underlying commodity prices during the year.

Notable changes in proved reserves during the year ended December 31, 2024, included:

- *Net change due to extensions and discoveries* - The increases are a result of additional development by the operators of the properties under which we own mineral interests. In 2024, a net addition of 4,639 MBOE occurred primarily from the completion of 1,519 new wells on our acreage and from the addition of 346 new proved undeveloped locations due to permitting and drilling activity.
- *Revisions* - Increases in oil & gas reserves include 136 MBOE due to revisions of previous quantity estimates, offset by a decline of 51 MBOE due to changes in the underlying commodity prices during the year.

Notable changes in proved reserves during the year ended December 31, 2025, included:

- *Net change due to extensions and discoveries* - The increases are a result of additional development by the operators of the properties under which we own mineral interests. In 2025, a net addition of 8,874 MBOE occurred primarily from the completion of 1,046 new wells on our acreage and from the addition of 309 new proved undeveloped locations due to permitting and drilling activity.
- *Revisions* - Decreases in oil & gas reserves include a decline of 1,624 MBOE due to revisions of previous quantity estimates and 11 MBOE due to changes in the underlying commodity prices during the year.

Standardized Measure of Discounted Future Net Cash Flows

Future cash inflows represent expected revenues from production of period-end quantities of proved reserves based on the 12-month unweighted average of first-of-the-month commodity prices for the years ended December 31, 2025, 2024 and 2023. All prices are adjusted for quality, transportation fees, energy content and regional basis differentials. Future cash inflows are computed by applying applicable prices relating to our proved reserves to the year-end quantities

of those reserves. Future production costs are derived based on current costs assuming continuation of existing economic conditions.

While due care was taken in preparation of the following cash flow projections, we do not represent that this data is the fair value of our oil & gas properties, or a fair estimate of the present value of cash flows to be obtained from their development and production. Material revisions to estimates of proved reserves may occur in the future; development and production of the reserves may not occur in the periods assumed; actual prices are expected to vary significantly from those used and actual costs may vary.

	As of December 31,					
	2025		2024		2023	
			(in thousands)			
	Consolidated	Our Share of an Equity Method Investee	Consolidated	Our Share of an Equity Method Investee	Consolidated	Our Share of an Equity Method Investee
Future cash inflows	\$ 908,678	28,684	\$ 849,345	32,472	\$ 914,461	34,986
Future production costs and severance taxes	(68,958)	(2,030)	(63,840)	(2,375)	(69,507)	(2,548)
Future income tax expense	(193,135)	—	(180,666)	—	(194,339)	—
Future net cash flows (undiscounted)	646,585	26,654	604,839	30,097	650,615	32,438
Annual discount 10% for estimated timing	(315,723)	(12,079)	(292,678)	(13,551)	(315,327)	(14,852)
Total standardized measure (1)	\$ 330,862	\$ 14,575	\$ 312,161	\$ 16,546	\$ 335,288	\$ 17,586

(1) Includes standardized discounted future net cash flows of approximately \$29.3 million, \$29.6 million and \$31.6 million attributable to noncontrolling interests in the ARLP Partnership's consolidated subsidiaries as of December 31, 2025, 2024 and 2023, respectively.

The average realized product prices weighted by production over the remaining lives of the properties are presented in the table below:

	For the Year Ended December 31,		
	2025	2024	2023
Oil (per Bbl)	\$ 64.89	\$ 75.22	\$ 77.61
Natural gas (per Mcf)	1.40	0.68	1.55
NGLs (per Bbl)	18.29	17.12	22.63

Changes in the standardized measure of discounted future net cash flows related to the proved oil & gas reserves of the properties are as follows:

	As of December 31,					
	2025		2024		2023	
	(in thousands)					
	Our Share of an Equity Method		Our Share of an Equity Method		Our Share of an Equity Method	
	Consolidated	Investee	Consolidated	Investee	Consolidated	Investee
Standardized measure, beginning of year	\$ 312,161	16,546	\$ 335,288	17,586	\$ 456,657	\$ 24,445
Purchases and sales of reserves in place, less related costs	11,018	—	9,126	—	17,519	—
Sales, net of production costs	(123,963)	(4,508)	(123,835)	(3,905)	(124,328)	(4,081)
Net changes due to extensions and discoveries	140,748	1,659	94,068	3,949	60,628	3,582
Net changes in prices and production costs	(47,520)	288	(30,539)	(1,825)	(185,935)	(7,960)
Revisions of previous quantity estimates	435	(1,421)	(11,655)	(525)	15,479	(686)
Net changes in income taxes	(5,610)	—	6,956	—	36,699	—
Accretion of discount	40,032	1,280	37,223	1,153	39,912	1,839
Changes in timing and other	3,561	731	(4,471)	113	18,657	447
Net increase (decrease) in standardized measures	18,701	(1,971)	(23,127)	(1,040)	(121,369)	(6,859)
Standardized measure, end of year	\$ 330,862	\$ 14,575	\$ 312,161	\$ 16,546	\$ 335,288	\$ 17,586

**SCHEDULE I – CONDENSED FINANCIAL INFORMATION OF REGISTRANT
ALLIANCE RESOURCE PARTNERS, L.P.**

CONDENSED BALANCE SHEETS (PARENT)
DECEMBER 31, 2025 AND 2024
(In thousands, except unit data)

	December 31,	
	2025	2024
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	\$ 1,916	\$ 1,942
Total current assets	1,916	1,942
OTHER ASSETS:		
Investments in consolidated subsidiaries	1,841,711	1,866,102
Total other assets	1,841,711	1,866,102
TOTAL ASSETS	<u>\$ 1,843,627</u>	<u>\$ 1,868,044</u>
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accrued taxes other than income taxes	\$ —	\$ 194
Total current liabilities	—	194
Total liabilities	—	194
PARTNERS' CAPITAL:		
Limited Partners - Common Unitholders 128,428,024 and 128,061,981 units outstanding, respectively	1,843,627	1,867,850
TOTAL LIABILITIES AND PARTNERS' CAPITAL	<u>\$ 1,843,627</u>	<u>\$ 1,868,044</u>

See accompanying notes.

CONDENSED STATEMENTS OF OPERATIONS (PARENT)
FOR THE YEARS ENDED DECEMBER 31, 2025, 2024 AND 2023
(In thousands, except unit and per unit data)

	Year Ended December 31,		
	2025	2024	2023
EXPENSES:			
General and administrative	\$ 60	\$ 301	\$ 151
Total operating expenses	60	301	151
LOSS FROM OPERATIONS	(60)	(301)	(151)
Interest income	75	94	57
Equity in earnings of consolidated subsidiaries	311,148	361,062	630,212
NET INCOME ATTRIBUTABLE TO ARLP	<u>\$ 311,163</u>	<u>\$ 360,855</u>	<u>\$ 630,118</u>
NET INCOME ATTRIBUTABLE TO ARLP			
GENERAL PARTNER	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 1,384</u>
LIMITED PARTNERS	<u>\$ 311,163</u>	<u>\$ 360,855</u>	<u>\$ 628,734</u>
EARNINGS PER LIMITED PARTNER UNIT - BASIC AND DILUTED	<u>\$ 2.40</u>	<u>\$ 2.77</u>	<u>\$ 4.81</u>
WEIGHTED-AVERAGE NUMBER OF UNITS OUTSTANDING – BASIC AND DILUTED	<u>128,387,910</u>	<u>127,964,744</u>	<u>127,180,312</u>

See accompanying notes.

CONDENSED STATEMENTS OF CASH FLOWS (PARENT)
FOR THE YEARS ENDED DECEMBER 31, 2025, 2024 AND 2023
(In thousands)

	Year Ended December 31,		
	2025	2024	2023
CASH FLOWS FROM OPERATING ACTIVITIES:	\$ 337,152	\$ 363,329	\$ 364,448
CASH FLOWS FROM FINANCING ACTIVITIES:			
Distributions paid to Partners	(337,178)	(363,430)	(364,579)
Net cash used in financing activities	(337,178)	(363,430)	(364,579)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(26)	(101)	(131)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	1,942	2,043	2,174
CASH AND CASH EQUIVALENTS AT END OF PERIOD	\$ 1,916	\$ 1,942	\$ 2,043

See accompanying notes.

NOTES TO FINANCIAL INFORMATION (PARENT)

1. BASIS OF PRESENTATION

In these parent-company-only financial statements, our investment in consolidated subsidiaries is stated at cost plus equity in undistributed earnings of subsidiaries and reduced by distributions received from subsidiaries since the date of acquisition. These parent-company-only financial statements should be read in conjunction with our consolidated financial statements in “Item 8. Financial Statements and Supplementary Data” of this Annual Report on Form 10-K.

2. GUARANTEES

As the parent of Alliance Coal and the Intermediate Partnership, ARLP is a guarantor of the Credit Facility and the 2029 Senior Notes discussed in “Item 8. Financial Statements and Supplementary Data—Note 12 – Long-Term Debt” of this Annual Report on Form 10-K. In addition to these guarantees, ARLP has provided guarantees on surety indemnity agreements and financially guaranteed certain coal supply agreements. The duration of these guarantees varies. The maximum undiscounted potential future payment obligation for our guarantees of certain coal supply agreements as of December 31, 2025 is approximately \$253.2 million. These guarantees provide for compensation to customers based on additional cost to the customer to replace any contracted tons that our subsidiaries fail to deliver. We do not expect to make any payments under these guarantees.

3. CASH DISTRIBUTIONS RECEIVED

We received distributions of \$337.2 million, \$363.4 million and \$364.6 million from our consolidated subsidiaries during the years ended December 31, 2025, 2024, and 2023, respectively.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures. We maintain controls and procedures designed to provide reasonable assurance that information required to be disclosed in the reports we file with the SEC is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and that such information is accumulated and communicated to our management, including the CEO and CFO, as appropriate, to allow for timely decisions regarding required disclosures. As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including the CEO and CFO, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) or Rule 15d-15(e) of the Exchange Act) as of December 31, 2025. Based on this evaluation, the CEO and CFO concluded that these controls and procedures are effective as of December 31, 2025.

Our management, including the CEO and CFO, does not expect that our disclosure controls or our internal controls over financial reporting will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the ARLP Partnership have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that simple errors or mistakes can occur. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based, in part, upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, controls may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our disclosure controls and internal controls and make modifications as necessary; our intent in this regard is that the disclosure controls and the internal controls will be maintained as systems change and conditions warrant.

Management's Annual Report on Internal Control over Financial Reporting. Management of the ARLP Partnership is responsible for establishing and maintaining effective internal control over financial reporting as defined in Rules 13a-15(f) under the Exchange Act. The ARLP Partnership's internal control over financial reporting is designed to provide reasonable assurance to our management and Board of Directors of our general partner regarding the preparation and fair presentation of published financial statements. Our controls are designed to provide reasonable assurance that the ARLP Partnership's assets are protected from unauthorized use and that transactions are executed in accordance with established authorizations and properly recorded. The internal controls are supported by written policies and are complemented by a staff of competent business process owners and an internal auditor supported by competent and qualified external resources used to assist in testing the operating effectiveness of the ARLP Partnership's internal control over financial reporting. Management concluded that the design and operations of our internal controls over financial reporting at December 31, 2025 are effective and provide reasonable assurance the books and records accurately reflect the transactions of the ARLP Partnership.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2025. In making this assessment, management used the criteria set forth by COSO in *Internal Control—Integrated Framework* (2013). Based on its assessment, management concluded that, as of December 31, 2025, the ARLP Partnership's internal control over financial reporting was effective based on those criteria, and management believes that we have no material internal control weaknesses in our financial reporting process.

Grant Thornton LLP, an independent registered public accounting firm, has made an independent assessment of the effectiveness of our internal control over financial reporting as of December 31, 2025, as stated in their report that is included herein.

Changes in Internal Controls Over Financial Reporting. There have not been any changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) or Rule 15d-15(f) of the Exchange Act) in the three months ended December 31, 2025 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors of Alliance Resource Management GP, LLC
and Unitholders of Alliance Resource Partners, L.P.

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of Alliance Resource Partners, L.P. (a Delaware limited partnership) and subsidiaries (the “Partnership”) as of December 31, 2025, based on criteria established in the 2013 Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”). In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2025, based on criteria established in the 2013 Internal Control—Integrated Framework issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (“PCAOB”), the consolidated financial statements of the Partnership as of and for the year ended December 31, 2025, and our report dated February 26, 2026 expressed an unqualified opinion on those financial statements.

Basis for opinion

The Partnership’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership’s internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and limitations of internal control over financial reporting

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

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

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
February 26, 2026

ITEM 9B. OTHER INFORMATION

During the three months ended December 31, 2025, no director or officer adopted or terminated (i) any contract, instructions or written plan for the purchase or sale of securities of the Partnership intended to satisfy the affirmative defense conditions of Rule 10b5-1(c) and/or (ii) any written arrangement for the purchase or sale of securities of the Partnership that meets the definition of a non-Rule 10b5-1 trading arrangement as defined in Item 408(c).

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE OF THE GENERAL PARTNER

As is commonly the case with publicly traded limited partnerships, we are managed and operated by our general partner. The following table shows information for executive officers and members of the Board of Directors as of the date of the filing of this Annual Report on Form 10-K. Executive officers and directors are elected until death, resignation, retirement, disqualification, or removal.

Name	Age	Position With Our General Partner
Joseph W. Craft III	75	Chairman, President and Chief Executive Officer
Megan J. Cordle	53	Vice President, Controller and Chief Accounting Officer
Cary P. Marshall	61	Senior Vice President and Chief Financial Officer
Jesse M. Parrish	40	Senior Vice President and Chief Commercial Officer of Alliance Coal, LLC
Steven C. Schnitzer	63	Senior Vice President, General Counsel and Secretary
Kirk D. Tholen	53	Senior Vice President; also President, Alliance Minerals, LLC
Mark Watson	49	Senior Vice President – Operations and Technology; also Chief Executive Officer, Matrix Design Group, LLC
Timothy J. Whelan	63	Senior Vice President – Sales and Marketing of Alliance Coal, LLC
Thomas M. Wynne	69	Senior Vice President and Chief Operating Officer
Nick Carter	79	Director and Member of Audit, Compensation* and Conflicts Committees
Robert J. Druten	78	Director and Member of Audit, Compensation and Conflicts* Committees
Ronna McDaniel	52	Director and Member of Audit, Compensation and Conflicts Committees
Wilson M. Torrence	84	Director and Member of Audit,* Compensation and Conflicts Committees
Paul H. Vining	71	Director**

* Indicates Chairman of Committee. ** Indicates Lead Director.

Joseph W. Craft III has been President, CEO and a Director since August 1999, Chairman of the Board of Directors since January 1, 2019, and indirectly owns our general partner. Previously Mr. Craft served as President of MAPCO Coal Inc. since 1986. During that period, he also was Senior Vice President of MAPCO Inc. and had previously been that company's General Counsel and Chief Financial Officer. He is a Director of the National Mining Association, and a Director and former Chairman of America's Power. Mr. Craft is a Director and former Chairman of the Kentucky Chamber of Commerce. He has been a Director of BOK Financial Corporation (NASDAQ: BOKF) since 2007 and chairman of its compensation committee since 2014. Mr. Craft holds both a Bachelor of Science degree in Accounting and a Juris Doctor degree from the University of Kentucky. Mr. Craft also is a graduate of the Senior Executive Program of the Alfred P. Sloan School of Management at the Massachusetts Institute of Technology. The specific experience, qualifications, attributes, or skills that led to the conclusion Mr. Craft should serve as a Director include his long history of significant involvement in the coal industry, his demonstrated business acumen and his exceptional leadership of the Partnership since its inception.

Megan J. Cordle became Vice President, Controller and Chief Accounting Officer in March 2022. Since joining the Partnership in October 1999, Ms. Cordle has held several positions of increasing responsibility, including Vice President and Assistant Controller. She held the position of Audit Manager with Deloitte & Touche LLP prior to joining the

Partnership. She is a certified public accountant and holds a Bachelor of Science in Business Administration degree with a major in Accounting from the University of Tulsa.

Cary P. Marshall became Senior Vice President and CFO in April 2023. Prior to his current position, Mr. Marshall previously served as Vice President, Corporate Finance and Treasurer since May 2003. Mr. Marshall joined Alliance in 1993 and has held several positions with increasing responsibilities in the finance and marketing areas. Mr. Marshall joined Alliance's predecessor, MAPCO Inc. in 1989 and held a variety of corporate finance positions. Mr. Marshall holds both a Bachelor of Business Administration degree and a Master of Business Administration degree from Southern Methodist University.

Jesse M. Parrish became Senior Vice President and Chief Commercial Officer of Alliance Coal in August 2025. Mr. Parrish joined Alliance Coal in April 2025 as Senior Vice President of Operations. Prior to joining Alliance Coal, Mr. Parrish spent more than a decade in senior leadership roles in the eastern U.S. coal industry, including serving as Chief Executive Officer of Blackhawk Mining, LLC from June 2020 to April 2025. During his long tenure at Blackhawk, Mr. Parrish held various positions of increasing responsibility, including President, Chief Financial Officer, and Vice President and Director of Strategic Planning and Corporate Communications. Before his career at Blackhawk, Mr. Parrish practiced law with Bingham Greenebaum Doll LLP, where he focused on coal related financings, mergers and acquisitions, and environmental matters. Mr. Parrish has previously served as chairman of both the West Virginia Coal Association and the Kentucky Coal Association and is a trustee of the Energy and Mineral Law Foundation. Mr. Parrish holds both a Bachelor of Business Administration in Finance and a Juris Doctor degree from the University of Kentucky.

Steven C. Schnitzer became Senior Vice President, General Counsel and Secretary in March 2024. Mr. Schnitzer previously served as Senior Vice President, General Counsel and Secretary of the general partner of both Arc Logistics Partners, LP (NYSE: ARCX), formerly a publicly traded limited partnership engaged in the midstream business, from February 2014 through the completion of its sale in December 2017, and Lightfoot Capital Partners, LP, the private equity sponsor of Arc Logistics Partners, from February 2014 through the completion of the sale of all its portfolio company investments in December 2018. From January 2019 through August 2023, Mr. Schnitzer served as Private Energy - General Counsel and Managing Director (or initially Director) of Tortoise Capital Advisors, L.L.C., which (together with its affiliates) is an energy and power infrastructure and energy transition asset management and advisory firm, and from September 2020 to August 2023 also served in a similar capacity on behalf of Tortoise Capital's affiliate, Ecofin Investments, LLC. During Mr. Schnitzer's tenure at Tortoise Capital, he served as Vice President, General Counsel and Secretary of Tortoise Acquisition Corp. (NYSE: SHLL), Tortoise Acquisition Corp. II (NYSE: SNPR) and TortoiseEcofin Acquisition Corp. III (NYSE: TRTL), which were special purpose acquisition corporations sponsored by affiliates of Tortoise Capital that evaluated or completed business combinations in the energy transition space. From June to August 2022, Mr. Schnitzer also served as the Interim General Counsel (or at times Special Counsel) of Volta Inc. (NYSE: VLTA), a developer and operator of EV charging station infrastructure that completed its business combination with Tortoise Acquisition Corp. II in August 2021. Mr. Schnitzer served as Chief Legal Officer and Secretary of Onyx Renewable Partners L.P., a commercial and industrial solar generation and battery storage developer, from September to December 2023. Mr. Schnitzer began his career at Debevoise & Plimpton, LLP in New York City, where he was an Associate in the Corporate Finance Department from 1988 to 1994. He was an Associate from 1994 and a Partner from 1997 to 2000 in the Corporate Group of Washington, DC-based Crowell & Moring LLP. From 2001 to January 2014, Mr. Schnitzer was the Chair of the Corporate Group of the Washington, DC office of Katten Muchin Rosenman LLP. Mr. Schnitzer holds a Bachelor of Arts degree from the University of Maryland and a Juris Doctor degree from Touro College Jacob D. Fuchsberg Law Center, where he graduated cum laude and served as Editor-in-Chief of the law review.

Kirk D. Tholen became Senior Vice President in December 2019 and also serves as President of the Partnership's oil & gas minerals business. Prior to his current position, Mr. Tholen most recently served as a Managing Director within the Oil & Gas Group and Head of the A&D Practice for Houlihan Lokey in Houston. From 2012 to 2015, he was Head of A&D for Credit Agricole CIB and was responsible for creating and leading their A&D platform to service domestic and cross-border client transactions as well as assisting in reserve-base lending, equity offerings and high-yield debt offerings. From 2006 to 2012, Mr. Tholen provided business development, marketing, transaction management, negotiating and closing services to clients at Albrecht & Associates, Inc., a sell-side E&P boutique advisory firm. His previous industry experience also includes serving as a Region Engineer for BJ Services from 1996 to 2006, where he provided drilling and fracturing technical services to clients operating in the lower 48 and Gulf of Mexico predominately as a dedicated in-house engineer focused on drilling and completions for BP, Conoco and Devon. Mr. Tholen began his career in 1992 joining UNOCAL's Louisiana inland waters and shallow shelf operation and reservoir engineering team. He holds a Bachelor of

Science degree in Chemical Engineering from the University of Louisiana at Lafayette and a Master of Business Administration degree from the University of Houston.

Mark Watson became Senior Vice President - Operations and Technology in July of 2024. Mr. Watson joined the Partnership's predecessor as an intern in 1994 and has held a variety of engineering and operations positions since joining the Partnership full-time in 2001. Since 2015, Mr. Watson has served as Chief Executive Officer of the Matrix Group, which he has led since 2006. Mr. Watson also oversees certain of the Partnership's investments in growth-stage companies. Mr. Watson holds both a Bachelor of Science and a Master of Science in Electrical Engineering from the University of Kentucky.

Timothy J. Whelan has been Senior Vice President - Sales and Marketing of Alliance Coal, LLC since May 2013. Since joining the Partnership in September 2003, Mr. Whelan has held several positions with increasing responsibility, including Vice President – Sales prior to his current position. Mr. Whelan previously served in various business development positions for MAPCO Inc. and as Director, Power & Gas Origination for Williams Energy Marketing and Trading. Mr. Whelan has over 30 years of energy industry experience and is a former board member of the American Coal Council and The Coal Institute. Mr. Whelan holds a Bachelor of Science degree in Finance from the University of Arkansas.

Thomas M. Wynne has been Senior Vice President and Chief Operating Officer since March 2009. Mr. Wynne joined the Partnership's predecessor in 1981 as a mining engineer and held a variety of positions of increasing responsibility prior to his appointment in July 1998 as Vice President—Operations. Mr. Wynne has served the coal industry on the National Executive Committee for National Mine Rescue and previously as a member of the Coal Safety Committee for the National Mining Association. In addition, Mr. Wynne is a past Chairman of the Kentucky Coal Association. Mr. Wynne holds a Bachelor of Science degree in Mining Engineering from the University of Pittsburgh and a Master of Business Administration degree from West Virginia University.

Nick Carter became a Director in April 2015. Mr. Carter is Chairman of the Compensation Committee and a member of the Audit and Conflicts Committees. Mr. Carter retired as President and Chief Operating Officer of Natural Resource Partners L.P. (NYSE: NRP) on September 1, 2014, having served in such capacities since 2002 and in other roles for NRP or its affiliates since 1990. Prior to 1990, Mr. Carter held various positions with MAPCO Coal Inc. and was engaged in the private practice of law. Mr. Carter previously served on the board of directors, the audit committee and as chairman of the compensation committee of Community Trust Bancorp, Inc. (NASDAQ: CTBI) and, beginning in December 2025, serves as chairman of the Board of Independence Power Holdings Inc. (OTC: IPHI). Mr. Carter also previously served as chairman of the National Council of Coal Lessors for 12 years, as chairman of the West Virginia Chamber of Commerce, and as a board member of the West Virginia Coal Association, the Indiana Coal Council, the National Mining Association, and ACCCE. Mr. Carter has served as a board member of the Kentucky Coal Association for over 20 years and currently is its Treasurer. Mr. Carter holds both a Bachelor of Science in Agriculture Economics degree and a Juris Doctor degree from the University of Kentucky and a Master of Business Administration degree from the University of Hawaii. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Carter should serve as a Director include his extensive experience in the coal and energy industries and in senior corporate leadership.

Robert J. Druten became a Director effective January 1, 2019. Mr. Druten is Chairman of the Conflicts Committee and is a member of the Audit and Compensation Committees. From January 2007 through 2018, Mr. Druten was a member of the board of directors of Alliance GP, LLC, the former general partner of AHGP. From September 1994 until his retirement in August 2006, Mr. Druten served as Executive Vice President and Chief Financial Officer of Hallmark Cards, Inc. Mr. Druten holds a Bachelor of Science degree in Accounting from the University of Kansas and a Master of Business Administration from Rockhurst University. Mr. Druten previously served as Chairman of the Board of Directors of Kansas City Southern Industries, Inc. (NYSE: KSU), a transportation and financial services company, and was Chairman of its executive committee and a member of its compensation committee and nominating and governance committees, and served as a trustee of the voting trust that held KSU from December 2021 to April 2023, at which time the Surface Transportation Board approved KSU's combination with Canadian Pacific Railway Limited. Mr. Druten previously served as a director of American Italian Pasta, from 2007 until it was acquired by Ralcorp Holdings in July 2010, where he was the Chair of its audit committee and also served on its compensation committee. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Druten should serve as Director are demonstrated by his lengthy and distinguished service as Chief Financial Officer of Hallmark, including direct oversight of a public company subsidiary, and his extensive experience serving as a director of public companies in multiple industries.

Ronna McDaniel became a Director in December 2024. Ms. McDaniel is a member of the Audit, Compensation and Conflicts Committees. Ms. McDaniel served as Chair of the Republican National Committee from 2017 until the first quarter of 2024, where she also chaired its executive committee, and served on the Board of Directors of the Romney Institute of Public Service and Ethics from 2016 to 2021. She served as Chair of the Michigan Republican Party from 2015 to 2017 and as chair of the Michigan Delegation at the 2016 Republican National Convention. Ms. McDaniel served as State Committeewoman in Michigan from 2012 to 2014. Ms. McDaniel holds a Bachelor of Arts degree in English from Brigham Young University. The specific experience, qualifications, attributes or skills that led to the conclusion Ms. McDaniel should serve as a Director include her skills in leadership, governance, public relations and organizational risk assessment, together with her skills in navigating complex regulatory environments.

Wilson M. Torrence became a Director in January 2007. Mr. Torrence is Chairman of the Audit Committee and a member of the Compensation and Conflicts Committees. From April 2015 through June 2018, Mr. Torrence was also a member of the board of directors of Alliance GP, LLC, the former general partner of AHGP, and chairman of its audit committee. Mr. Torrence retired from Fluor Corporation in 2006 as a Senior Vice President of Project Development and Investments and after retirement has performed investment and business consulting services for various clients. Mr. Torrence was employed at Fluor from 1989 to 2006 where, among other roles, he was responsible for the global Project Investment and Structured Finance Group and served as Chairman of Fluor's Investment Committee. In that position, Mr. Torrence had executive responsibility for Fluor's global activities in developing and arranging third-party financing for some of Fluor's clients' construction projects. Prior to joining Fluor in 1989, Mr. Torrence was President and CEO of Combustion Engineering Corporation's Waste to Energy Division and, during that time, also served as Chairman of the Institute of Resource Recovery, a Washington-based industry advocacy organization. Mr. Torrence began his career at Mobil Oil Corporation, where he held several executive positions, including Assistant Treasurer of Mobil's International Marketing and Refining Division and Chief Financial and Planning Officer of Mobil Land Development Company. Mr. Torrence holds both a Bachelor degree and a Master of Business Administration degree from Virginia Tech University. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Torrence should serve as a Director include his extensive experience in the construction and energy businesses, his senior corporate finance-related and other leadership positions and his participation in numerous financing transactions.

Paul H. Vining became a Director in July 2024 and serves as Lead Director. Mr. Vining has served as Chairman of the Board of Directors of Westmoreland Mining, LLC, a privately held coal producer with active surface mines in Montana and Western Canada, since October 2019, and as Chairman of the Board of Directors of The Frazier Quarry Inc., a privately held quarry and aggregates company, from July 2023 to January 2025. From May through July 2022, Mr. Vining served as Chairman of the Board of Directors of Allegiance Coal Limited (ASX: AHQ), an Australian securities exchange listed company engaged in seaborne met coal mine development and operations, and from 2016 to 2019 served as a member of the Board of Directors of the general partner of then NYSE-listed Foresight Energy LP, a producer of thermal coal. Mr. Vining began his career in 1979 as a mineral engineer and has held a variety of senior executive positions over the years with several companies, including as Chief Executive Officer of Minerals Refining Company, a company with technology that recovers ultra-fine minerals particles from minerals waste, throughout 2022, Executive Vice President Global Investment and Development for Xcoal Energy and Resources LLC, an international coal export and trading company, from 2019 to 2021, and Chief Executive Officer of The Cline Group, LLC, a developer of thermal coal mines in the United States and Canada, from 2015 to 2019. Prior to that, Mr. Vining held senior executive positions in several major companies including as Chief Operating Officer and then President of Alpha Natural Resources, Inc., President and Chief Operating Officer of Patriot Coal Company, Chief Executive Officer of Magnum Coal Company, Chief Commercial Officer of Arch Coal Inc. and Chief Commercial Officer of Peabody. Earlier in his career, Mr. Vining held various commercial and marketing positions at Massey Energy Company, Occidental Petroleum Corp., and ENI S.p.A. Mr. Vining holds both a Bachelor degree and a Master of Science degree in Mining and Minerals Engineering from Columbia University and a Bachelor of Science degree in Chemistry from the College of William and Mary. The specific experience, qualifications, attributes or skills that led to the conclusion Mr. Vining should serve as a Director include his extensive experience in the natural resources mining industry, his extensive service on the boards of directors of and in senior corporate leadership positions for companies engaged in such industry, his experience in business development, operations, financial matters and transactions, and his mining and minerals engineering degree.

Board of Directors

Mr. Craft, who has been President and CEO and a member of the Board of Directors since ARLP's inception, assumed the Chairman role effective January 1, 2019. We believe this leadership structure of the Board of Directors is appropriate

for the Partnership given Mr. Craft's extensive knowledge of our industries, significant ownership position, and proven leadership of the Partnership.

In 2024, Mr. Vining was elected to the Board of Directors and serves in the capacity as Lead Director. In such capacity, Mr. Vining assists the Board of Directors and management on planning and other initiatives as directed from time to time by the Board of Directors or Mr. Craft.

The Board of Directors generally administers its risk oversight function through the board as a whole. The Chairman, President and CEO, who reports to the Board of Directors, and the other executives named above, who report to the Chairman, President and CEO or, in the case of Mrs. Cordle, the CFO, have day-to-day risk management responsibilities. At the Board of Directors' request, each of these executives attends the meetings of the Board of Directors, where the Board of Directors routinely receives reports on our financial results, the status of our operations and our safety performance, and other aspects of the implementation of our business strategy, with ample opportunity for specific inquiries of management. In addition, management provides periodic reports of the Partnership's financial and operational performance to each member of the Board of Directors. The Audit Committee provides additional risk oversight through its quarterly meetings, where it receives a report from the Partnership's internal auditor, who reports directly to the Audit Committee, and reviews the Partnership's contingencies, significant transactions and subsequent events, among other matters, with management and our independent auditors.

The Board of Directors has selected as director nominees individuals with experience, skills and qualifications relevant to the business of the Partnership, such as experience in energy or related industries or with financial markets or in regulatory affairs, expertise in mining, engineering or finance, and a history of service in senior leadership positions. The Board of Directors has not established a formal process for identifying director nominees but has endeavored to assemble a talented group of individuals with the qualities and attributes required to provide effective oversight of the Partnership.

Audit Committee

The Audit Committee comprises four of five non-employee members of the Board of Directors (Messrs. Carter, Druten and Torrence and Ms. McDaniel). After reviewing the qualifications of the current members of the Audit Committee, and any relationships they may have with us that might affect their independence, the Board of Directors has determined that all current Audit Committee members are "independent" as that concept is defined in Section 10A of the Exchange Act, all current Audit Committee members are "independent" as that concept is defined in the applicable rules of NASDAQ Stock Market, LLC, all current Audit Committee members are financially literate, and Mr. Torrence qualifies as an "audit committee financial expert" under the applicable rules promulgated pursuant to the Exchange Act.

Report of the Audit Committee

The Audit Committee oversees our financial reporting process on behalf of the Board of Directors. Management has primary responsibility for the financial statements and the reporting process including the systems of internal controls. The Audit Committee has responsibility for the appointment, compensation and oversight of the work of our independent registered public accounting firm and assists the Board of Directors by conducting its own review of our:

- filings with the SEC pursuant to the Securities Act and the Exchange Act (*e.g.*, Forms 10-K, 10-Q, and 8-K);
- press releases and other communications by us to the public concerning earnings, financial condition and results of operations, including changes in distribution policies or practices affecting the holders of our units, if such review is not undertaken by the Board of Directors;
- systems of internal controls regarding finance and accounting that management and the Board of Directors have established; and
- auditing, accounting and financial reporting processes generally.

In fulfilling its oversight and other responsibilities, the Audit Committee met eight times during 2025. The Audit Committee's activities included, but were not limited to: (a) selecting the independent registered public accounting firm, (b) meeting periodically in executive session with the independent registered public accounting firm, (c) reviewing the Quarterly Reports on Form 10-Q for the three months ended March 31, June 30, and September 30, 2025, (d) performing

a self-assessment of the committee, (e) reviewing the Audit Committee charter, and (f) reviewing the overall scope, plans and findings of our internal auditor. Based on the results of the annual self-assessment, the Audit Committee believes that it satisfied the requirements of its charter. A copy of the Audit Committee charter is publicly available on our website under “Investor Relations” at www.arlp.com and is available in print without charge to any unitholder who requests it. Such requests should be directed to Investor Relations at (918) 295-7673. The Audit Committee also reviewed and discussed with management and the independent registered public accounting firm this Annual Report on Form 10-K, including the audited financial statements.

Our independent registered public accounting firm, Grant Thornton, is responsible for expressing an opinion on the conformity of the audited financial statements with GAAP. The Audit Committee reviewed with Grant Thornton its judgment as to the quality, not just the acceptability, of our accounting principles and such other matters as are required to be discussed with the Audit Committee pursuant to the applicable requirements of the PCAOB and the SEC.

The Audit Committee received written disclosures and the letter from Grant Thornton required by applicable requirements of the PCAOB Rule 3526, “Communication with Audit Committees Concerning Independence,” and has discussed with Grant Thornton its independence from management and the ARLP Partnership.

Based on the reviews and discussions referred to above, the Audit Committee recommended to the Board of Directors that the audited financial statements be included in the Annual Report on Form 10-K for the year ended December 31, 2025 for filing with the SEC.

Members of the Audit Committee:

Wilson M. Torrence, Chairman
Nick Carter
Robert J. Druten
Ronna McDaniel

Code of Ethics

We have adopted a code of ethics with which the Chairman, President and CEO and the senior financial officers (including the principal financial officer and the principal accounting officer) are expected to comply. The code of ethics is publicly available on our website under “Investor Relations” at www.arlp.com and is available in print without charge to any unitholder who requests it. Such requests should be directed to Investor Relations at (918) 295-7673. If any substantive amendments are made to the code of ethics or if there is a grant of a waiver, including any implicit waiver, from a provision of the code to the President and CEO, Chief Financial Officer, or Chief Accounting Officer, we will disclose the nature of such amendment or waiver on our website or in a report on Form 8-K. There were no such amendments or waivers during the year ended December 31, 2025.

Insider Trading Policy

We have an insider trading policy governing transactions in ARLP’s securities and derivative securities relating to ARLP’s units that applies to any employee, officer, or director of the Partnership as well as to the Partnership. We believe that our insider trading policy is reasonably designed to promote compliance with insider trading laws, rules and regulations, and listing standards applicable to the Partnership. A copy of the Partnership’s insider trading policy is filed as Exhibit 19.1 to this Annual Report on Form 10-K.

Communications with the Board

Unitholders or other interested parties can contact any director or committee of the Board of Directors by writing to them c/o Senior Vice President, General Counsel and Secretary, P.O. Box 22027, Tulsa, Oklahoma 74121-2027. Comments or complaints relating to our accounting, internal accounting controls or auditing matters will also be referred to members of the Audit Committee. The Audit Committee has procedures for (a) receipt, retention and treatment of complaints received by us regarding accounting, internal accounting controls, or auditing matters and (b) the confidential, anonymous submission by our employees of concerns regarding questionable accounting or auditing matters.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act, as amended, requires directors, executive officers and persons who beneficially own more than ten percent of a registered class of our equity securities to file with the SEC initial reports of ownership and reports or changes in ownership of such equity securities. Based on a review of the copies of the forms furnished to us and written representations from certain reporting persons, we believe that during 2025 none of our directors or executive officers or persons who beneficially owned more than ten percent of a registered class of our equity securities were delinquent with respect to any of the filing requirements under Section 16(a), with the following exceptions: Mark Watson, Senior Vice President – Operations and Technology; also Chief Executive Officer, Matrix Design Group, LLC, filed a Form 4 on January 31, 2025 that included a transaction occurring on January 28, 2025 and Jesse M. Parrish, Senior Vice President and Chief Commercial Officer of Alliance Coal, LLC, filed a Form 3 on August 13, 2025 resulting from a promotion effective on August 1, 2025.

Reimbursement of Expenses of our General Partner and its Affiliates

Our general partner does not receive any management fee or other compensation in connection with its management of us. Our general partner is reimbursed by us for all expenses incurred on our behalf. Please see “Item 13. Certain Relationships and Related Transactions, and Director Independence—Other Related-Party Transactions--*Expense Reimbursements.*”

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

Introduction

The Compensation Committee oversees the compensation of our general partner's executive officers, including the Named Executive Officers, each of whom is named in the Summary Compensation Table. Our Named Executive Officers are employees of our operating subsidiary, Alliance Coal.

Compensation Objectives and Philosophy

The compensation of our Named Executive Officers is designed to achieve three key objectives: (i) provide a competitive compensation opportunity to allow us to recruit and retain key management talent, (ii) align executive officers' interests with unitholder interests and (iii) motivate and reward the executive officers for creating sustainable, capital-efficient growth in available cash to maximize unitholder returns. In making decisions regarding executive compensation, the Compensation Committee reviews current compensation levels of peer company executives in similar roles as the Named Executive Officers, considers the Chairman, President and CEO's assessment of each of the other executives, and uses its discretion to determine an appropriate total compensation package of base salary and short-term and long-term incentives. The Compensation Committee intends for each executive officer's total compensation to be competitive in the marketplace and to effectively motivate the officer. Based on its review of our overall executive compensation program, the Compensation Committee believes the program is appropriately applied to our general partner's executive officers and is necessary to attract and retain the executive officers who are essential to our continued development and success, to compensate those executive officers for their contributions and to enhance unitholder value. Moreover, the Compensation Committee believes the total compensation opportunities provided to our general partner's executive officers create alignment with our long-term interests and those of our unitholders. As a result, we do not maintain unit ownership requirements for our Named Executive Officers.

Setting Executive Compensation

Role of the Compensation Committee

The Compensation Committee discharges the Board of Directors' responsibilities relating to our general partner's executive compensation program. The Compensation Committee oversees our compensation and benefit plans and policies, administers our incentive bonus and equity participation plans, and reviews and approves annually all compensation decisions relating to our Named Executive Officers. The Compensation Committee is empowered by the Board of Directors and by the Compensation Committee's charter to make all decisions regarding compensation for our Named Executive Officers without ratification or other action by the Board of Directors. The Compensation Committee has the authority to secure services for executive compensation matters, legal advice, or other expert services, both from within and outside the company. While the Compensation Committee is empowered to delegate all or a portion of its duties to a subcommittee, it has not done so.

The Compensation Committee comprises all of our directors who have been determined to be "independent" by the Board of Directors in accordance with applicable NASDAQ Stock Market, LLC and SEC regulations, presently Messrs. Carter, Druten and Torrence and Ms. McDaniel.

Role of Executive Officers

Each year, the Chairman, President and CEO submits recommendations to the Compensation Committee for adjustments to the salary, bonuses and long-term equity incentive awards payable to our Named Executive Officers, excluding himself. The Chairman, President and CEO bases his recommendations on his assessment of each executive's performance, experience, demonstrated leadership, job knowledge and management skills. The Compensation Committee considers the recommendations of the Chairman, President and CEO as one factor in making compensation decisions regarding our Named Executive Officers. Historically, and in 2025, the Compensation Committee and the Chairman, President and CEO have been substantially aligned on decisions regarding the compensation of the Named Executive Officers. As executive officers are promoted or hired during the year, the Chairman, President and CEO makes

compensation recommendations to the Compensation Committee and works closely with the Compensation Committee to ensure that all compensation arrangements for executive officers are consistent with our compensation philosophy and are approved by the Compensation Committee. At the direction of the Compensation Committee, the Chairman, President and CEO and the Senior Vice President, General Counsel and Secretary attend certain meetings of the Compensation Committee.

Use of Peer Group Comparisons

The Compensation Committee believes that it is important to review and compare our performance with that of peer companies and reviews the composition of the peer group annually. The peer group represents organizations of such size and complexity of operations in the coal industry and the oil & gas minerals industry as deemed relevant to the Compensation Committee. For 2025, the peer group consisted of the following companies: Alpha Metallurgical Resources, Inc., Black Stone Minerals, L.P., CORE Natural Resources, Inc., Dorchester Minerals, L.P., Kimbell Royalty Partners, LP, Natural Resource Partners L.P., Peabody, Sitio Royalties Corp., and Warrior Met Coal, Inc. In assessing the competitiveness of our executive compensation program for 2025, the Compensation Committee, with the assistance of the Chairman, President and CEO, collected and analyzed publicly available data from the peer group, including proxy information, annual reports, and other disclosures, and developed a comparative analysis of base salaries, short-term incentives, total cash compensation, long-term incentives, and total compensation to align with the role performed by each of our Named Executive Officers. The Compensation Committee uses the peer group data as a point of reference for comparative purposes, but it is not the determinative factor for the compensation of our Named Executive Officers. The Compensation Committee exercises discretion in determining the nature and extent of the use of comparative pay data.

Consideration of Equity Ownership and CEO Compensation

Mr. Craft, the Chairman, President and CEO, is evaluated and treated differently with respect to compensation than our other Named Executive Officers. Mr. Craft and related entities own significant equity positions in ARLP and Mr. Craft indirectly owns our general partner. Because of these ownership positions, the interests of Mr. Craft are directly aligned with those of our unitholders. Mr. Craft has not received an increase in base salary since 2002, has not received a bonus under our STIP since 2005 and did not receive any grants of LTIP awards from 2005 through 2015. On January 22, 2016, the Compensation Committee approved an LTIP award for Mr. Craft that vested on January 1, 2019. Mr. Craft has not received any subsequent LTIP awards. Beginning in February 2016, at Mr. Craft's request, his annual base salary was reduced to \$1.

Employment Agreements

We have not historically maintained employment agreements with any of our Named Executive Officers. However, we provided an employment letter to our Senior Vice President, General Counsel and Secretary, Mr. Schnitzer, in connection with his hiring in March 2024 setting forth the terms of his employment, which we determined was necessary to successfully hire Mr. Schnitzer and in the best interests of the Partnership. For more information regarding the compensation and potential severance provisions of the Schnitzer Employment Letter, see "Item 11. Executive Compensation—"Narrative Disclosure Relating to the Summary Compensation Table and Grants of Plan-Based Awards Table" and "Potential Payments Upon a Termination or Change in Control."

Compensation Components

Overview

The principal components of compensation for our Named Executive Officers (other than Mr. Craft) include:

- base salary;
- annual cash incentive bonus awards under the STIP; and
- awards of restricted units under the LTIP, including DERs.

The relative amount of each component is not based on any formula, but rather is based on the recommendation of the Chairman, President and CEO, subject to the discretion of the Compensation Committee to make any modifications it deems appropriate.

All executive officers, including the Named Executive Officers, are entitled to customary benefits available to our employees generally, including group medical, dental, and life insurance and participation in our PSSP. Our PSSP is a defined contribution plan and includes an employer matching contribution of 75% on the first 3% of eligible compensation contributed by the employee, an employer non-matching contribution of 0.75% of eligible compensation, and an employer supplemental contribution of 5% of eligible compensation. The PSSP provides an additional means of attracting and retaining qualified employees by providing tax-advantaged opportunities for employees to save for retirement.

Base Salary

When reviewing base salaries, the Compensation Committee's policy is to consider the individual's experience, tenure and performance, the individual's level of responsibility, the position's complexity and its importance to us in relation to other executive positions, our financial performance, and competitive pay practices. The Compensation Committee also considers comparative compensation data of companies in our peer group and the recommendation of the Chairman, President and CEO of our general partner. Base salaries are reviewed annually to ensure continuing consistency with market levels, and adjustments to base salaries are made as needed to reflect movement in the competitive market as well as individual performance. During 2025, our Named Executive Officers other than Mr. Craft received an increase in salary as follows: Mr. Marshall, \$35,000 increase to \$335,000; Mr. Schnitzer, \$15,000 increase to \$415,000; Mr. Tholen, \$60,000 increase to \$560,000; and Mr. Wynne, \$130,000 to \$560,000.

Annual Cash Incentive Bonus Awards

The STIP is designed to assist us in attracting, retaining and motivating qualified personnel by rewarding management, including our Named Executive Officers, and selected other salaried employees with cash awards for our achievement of an annual financial performance target. The annual performance target is recommended by the Chairman, President and CEO and approved by the Compensation Committee, typically in January of each year. The performance measure is subject to equitable adjustment in the sole discretion of the Compensation Committee to reflect the occurrence of any significant events during the year.

The performance target historically has been EBITDA-based, with items added or removed from the EBITDA calculation to ensure that the performance target reflects the operating results of our core businesses. (EBITDA is defined as net income of ARLP before net interest expense, income taxes, depreciation, depletion and amortization and net income attributable to noncontrolling interest.) The aggregate cash available for awards under the STIP each year is dependent on our actual financial results for the year compared to the annual performance target, and it increases in relation to our EBITDA, as adjusted, exceeding the minimum threshold. Our STIP Guidelines provide that achieving the minimum threshold is the minimum acceptable result for a performance pay-out to occur under the STIP, although the Compensation Committee may determine satisfactory results and adjust the size of the pay-out pool in its sole discretion. In 2025, the Compensation Committee approved a minimum financial performance target of \$595.0 million in EBITDA from current operations, normalized by excluding any charges for unit-based and directors' compensation as well as other equitable adjustments determined to be appropriate by the Compensation Committee. For 2025, we met the minimum performance target.

Individual awards to our Named Executive Officers each year are determined by the Compensation Committee. However, the Compensation Committee does not establish individual target payout amounts for the Named Executive Officers' STIP awards. As it does when reviewing base salaries, in determining individual awards under the STIP, the Compensation Committee considers its assessment of the individual's performance, our financial performance, comparative compensation data of companies in our peer group and the recommendation of the Chairman, President and CEO, although EBITDA-based performance targets described above are given significant weight. The compensation expense associated with STIP awards is recognized in the year earned, with the cash awards generally payable in the first quarter of the following calendar year. Termination of employment of an executive officer for any reason prior to payment of a cash award will result in forfeiture of any right to the award, unless and to the extent waived by the Compensation Committee in its discretion.

The performance measure for the STIP in 2026 will be based on adjusted EBITDA for current operations, excluding charges for unit-based and directors' compensation. As discussed above, the Compensation Committee may, in its discretion, make equitable adjustments to the performance criteria under the STIP and adjust the amount of the aggregate

pay-out. The Compensation Committee believes the STIP performance criteria for 2026 will be reasonably difficult to achieve and therefore support our key compensation objectives discussed above.

The Compensation Committee maintains discretion to grant cash bonus awards outside of the STIP to address special situations.

Equity Awards under the LTIP

Equity compensation pursuant to the LTIP is a key component of our executive compensation program. Our LTIP is sponsored by Alliance Coal. Under the LTIP, grants may be made of either (a) restricted units, (b) options to purchase common units (although to date, no grants of options have been made) or (c) cash awards. The Compensation Committee has the authority to determine the participants to whom restricted units are granted, the number of restricted units to be granted to each such participant, and the conditions under which the restricted units may become vested, including the duration of any vesting period. Annual grant levels for designated participants (including our Named Executive Officers) are recommended by our general partner's Chairman, President and CEO, subject to review and approval by the Compensation Committee. Grant levels are intended to support the objectives of the comprehensive compensation package described above. The LTIP grants provide our Named Executive Officers with the opportunity to achieve a meaningful ownership stake in the Partnership, thereby assuring that their interests are aligned with our success. Even though Mr. Craft has not been granted an award under the LTIP since 2005, with the exception of one grant in 2016, the Compensation Committee believes Mr. Craft's interests are directly aligned with the interests of our unitholders as a result of his ownership positions. There is no formula for determining the size of awards to any individual recipient and, as it does when reviewing base salaries and individual STIP payments, the Compensation Committee considers its assessment of the individual's performance, our financial performance, compensation levels at peer companies in the coal industry and the recommendation of the Chairman, President and CEO. Amounts realized from prior grants, including amounts realized due to changes in the value of our common units, are not considered in setting grant levels or other compensation for our Named Executive Officers.

Restricted Units. Restricted units granted under the LTIP are "phantom" or notional units that upon vesting entitle the participant to receive an ARLP common unit. Restricted units granted under the LTIP vest at the end of a stated period from the grant date, provided we achieve an aggregate performance target for that period. However, if a grantee's employment is terminated for any reason prior to the vesting of any restricted units, those restricted units will generally be forfeited, (i) unless the Compensation Committee, in its sole discretion, determines otherwise or (ii) except as provided otherwise in the LTIP or under any written compensatory agreement. The number of units distributed upon satisfaction of the applicable vesting requirements is reduced to cover the income tax withholding requirement for each individual participant based on the fair market value of the common units as of the date of distribution. At the Compensation Committee's discretion, grants of restricted units under the LTIP may include the contingent right to receive quarterly distributions in an amount equal to the cash distributions we make to unitholders during the vesting period. DERs are payable, in the discretion of the Compensation Committee, either in cash or in the form of additional Restricted Units credited to a book-keeping account subject to the same vesting restrictions as the tandem award.

The performance target applicable to restricted unit awards under the LTIP is based on a normalized EBITDA measure and requires achieving an aggregate performance level for the vesting period. We typically issue grants under the LTIP at the beginning of each year, with the exception of new employees who begin employment with us at some other time and job promotions that may occur at some other time. The compensation expense associated with LTIP grants is recognized over the vesting period in accordance with FASB ASC 718, *Compensation — Stock Compensation*.

Our general partner's policy is to grant restricted units pursuant to the LTIP to serve as a means of incentive compensation for performance. Therefore, no consideration will be payable by the LTIP participants upon receipt of the common units. Common units to be delivered upon the vesting of restricted units may be common units we already own, common units we acquire in the open market or from any other person, newly issued common units, or any combination of the foregoing. If we issue new common units upon payment of the restricted units instead of purchasing them, the total number of common units outstanding will increase.

The LTIP provides the Compensation Committee with the discretion to determine the conditions for vesting (as well as all other terms and conditions) associated with any award under the plan, and to amend any of those conditions so long as an amendment does not materially reduce the benefit to the participant. The Compensation Committee believes the performance-related vesting conditions of all outstanding awards under the LTIP will be reasonably difficult to satisfy and therefore support our key compensation objectives discussed above.

Grants for 2025 under the LTIP, authorized on January 28, 2025, will cliff vest on January 1, 2028, provided we achieve a target level of aggregate EBITDA for current operations, excluding any charges for unit-based and directors' compensation, for the period January 1, 2025 through December 31, 2027. Regardless of achieving the EBITDA target, the 2025 grants have a minimum value guarantee of either \$19.99 or \$13.33 per unit as the case may apply to a specific grant recipient. Grants for 2026 under the LTIP, authorized on January 27, 2026, will cliff vest on January 1, 2029, provided we achieve a target level of aggregate EBITDA for current operations, excluding any charges for unit-based and directors' compensation, for the period January 1, 2026 through December 31, 2028. Regardless of achieving the EBITDA target, the 2026 grants have a minimum value guarantee of either \$17.89 or \$11.93 per unit as the case may apply to a specific grant recipient.

Unit Options. We have not made any grants of unit options. The Compensation Committee, in the future, may decide to make unit option grants to employees and directors on terms determined by the Compensation Committee.

Policies and Practices Related to the Grant of Certain Equity Awards in Relation to the Release of Material Non-Public Information. Although we do not currently have a formal practice or policy regarding equity award grant timing, the Compensation Committee does not time, nor has the Compensation Committee in the past timed, the grant of LTIP awards in coordination with the release of material non-public information. Instead, LTIP awards are granted only at the time or times dictated by our normal compensation process as developed by the Compensation Committee.

Effect of a Change in Control. Upon a "change in control" as defined in the LTIP (and described below), all awards outstanding under the LTIP will automatically vest and become payable or exercisable, as the case may be, in full. Please see "Item 11. Executive Compensation—Potential Payments Upon a Termination or Change in Control" for additional information regarding the treatment of equity upon a change in control.

Amendments and Termination. The Board of Directors or the Compensation Committee may, in its discretion, terminate the LTIP at any time with respect to any common units for which a grant has not previously been made. Except as required by the rules of the exchange on which the common units may be listed at that time, the Board of Directors or the Compensation Committee may alter or amend the LTIP in any manner from time to time; provided, however, that no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of the affected participant. In addition, the Board of Directors or the Compensation Committee may, in its discretion, establish such additional compensation and incentive arrangements as it deems appropriate to motivate and reward our employees.

Other Compensation-Related Matters

Insider Trading Policy; Prohibitions on Hedging and Trading in Derivatives

To ensure alignment of the interests of our unitholders with our directors and all officers, including Named Executive Officers, the Partnership's Insider Trading Policy prohibits any employee, officer, or director of the Partnership or any of its subsidiaries from engaging in trading involving (1) options or other derivative securities relating to ARLP units; (2) debt securities of ARLP or its affiliates; (3) hedging transactions involving ARLP securities; or (4) purchases of ARLP units on margin. Please read "Item 10. Directors, Executive Officers and Corporate Governance of the General Partner – Insider Trading Policy" for a discussion of our Insider Trading Policy.

Tax Deductibility of Compensation

The deduction limitations imposed under Section 162(m) of the Internal Revenue Code do not apply to compensation paid to our Named Executive Officers because we are a limited partnership and not a "corporation" within the meaning of Section 162(m).

Perquisites and Personal Benefits

The Partnership provides a limited amount of perquisites and personal benefits to the Named Executive Officers in keeping with the Compensation Committee's objectives to provide competitive compensation to motivate and reward executive officers for creating sustainable, capital-efficient growth in available cash. These perquisites and personal benefits typically include amounts for items such as tax preparation fees and annual physical medical exams, and are reviewed annually by the Compensation Committee.

Clawback Policy

We maintain the Alliance Resource Partners, L.P. Incentive-Based Compensation Recoupment Policy (the “Clawback Policy”), which is administered by the Compensation Committee. The Clawback Policy authorizes the Compensation Committee to recoup incentive compensation from applicable officers, including each of the Named Executive Officers, in the event of a restatement of financial statements. A copy of the Clawback Policy is filed as Exhibit 97.1 to this Annual Report on Form 10-K.

Compensation Committee Report

The Compensation Committee has submitted the following report for inclusion in this Annual Report on Form 10-K:

Our Compensation Committee has reviewed and discussed the Compensation Discussion and Analysis contained in this Annual Report on Form 10-K with management. Based on our Compensation Committee’s review of and the discussions with management with respect to the Compensation Discussion and Analysis, our Compensation Committee recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K for the fiscal year ended December 31, 2025.

The foregoing report is provided by the following directors, who constitute all the members of the Compensation Committee:

Members of the Compensation Committee:

Nick Carter, Chairman
Robert J. Druten
Ronna McDaniel
Wilson M. Torrence

Notwithstanding anything to the contrary set forth in any of our previous filings under the Securities Act or the Exchange Act, that incorporate future filings, including this Annual Report on Form 10-K, in whole or in part, the foregoing Compensation Committee Report shall not be deemed to be filed with the SEC or incorporated by reference into any filing under the Securities Act or the Exchange Act, except to the extent that we specifically incorporate it by reference.

Summary Compensation Table

The table below sets forth all the compensation awarded to, earned by, or paid to our Named Executive Officers during fiscal year ended December 31, 2025 and, to the extent required by applicable SEC disclosure rules for individuals that were “named executive officers” in applicable years, during the fiscal years ended December 31, 2024 and 2023.

Name and Principal Position	Year	Salary \$(1)	Bonus \$(2)	Unit Awards \$(3)	Non-Equity Incentive Plan Compensation \$(4)	All Other Compensation \$(5)	Total
Joseph W. Craft III	2025	1	—	—	—	—	1
President, Chief Executive	2024	1	—	—	—	—	1
Officer and Chairman	2023	1	—	—	—	—	1
Cary P. Marshall,	2025	332,308	—	659,489	303,000	41,685	1,336,482
Senior Vice President and	2024	300,000	—	590,466	143,580	40,484	1,074,530
Chief Financial Officer	2023	293,269	26,340	666,555	220,000	63,368	1,269,532
Steven C. Schnitzer	2025	413,846	688,000	646,724	272,500	28,000	2,049,070
Senior Vice President,	2024	324,615	552,000	566,256	159,540	25,969	1,628,380
General Counsel and Secretary							
Kirk D. Tholen	2025	555,385	—	775,153	506,800	28,000	1,865,338
Senior Vice President; also	2024	500,000	—	650,289	239,300	27,600	1,417,189
President Alliance Minerals, LLC	2023	500,000	1,000,000	734,083	341,000	223,014	2,798,097
Thomas M. Wynne	2025	550,000	—	753,528	506,800	40,900	1,851,228
Senior Vice President and	2024	430,000	—	650,289	205,800	40,500	1,326,589
Chief Operating Officer	2023	430,000	58,393	734,083	345,000	101,155	1,668,631

- (1) Amounts represent the salary earned by each Named Executive Officer for the respective year or, in the case of Mr. Schnitzer, since the date of his hire in 2024.
- (2) Amounts for Mr. Schnitzer represent the portion of his signing bonus paid in 2025 and 2024 pursuant to the Schnitzer Employment Letter. The final installment of such signing bonus was paid to Mr. Schnitzer in February 2026. The amounts for Mr. Marshall, Mr. Tholen and Mr. Wynne represent the second payment of their 2020 service-based vesting LTIP awards which were paid in cash in February 2023.
- (3) The Unit Awards represent the aggregate grant date fair value of restricted units granted pursuant to FASB ASC 718, using the same assumptions as used for financial reporting purposes and which are more fully described in “Item 8. Financial Statements and Supplementary Data—Note 18 – Common Unit-Based Compensation Plans,” to each Named Executive Officer under the LTIP in the respective year. Please see “Item 11. Compensation Discussion and Analysis—Compensation Program Components—*Equity Awards under the LTIP*” for a description of the terms of the awards.
- (4) Amounts represent the STIP bonus earned for the respective year. STIP payments typically are made in the first quarter of the year following the year in which they are earned. Please see “Item 11. Compensation Discussion and Analysis—Compensation Program Components—*Annual Cash Incentive Bonus Awards*.”

- (5) The amounts represent the sum of the (a) profit sharing savings plan employer contribution and (b) perquisites in excess of \$10,000. A reconciliation of the 2025 amounts is as follows:

	Profit Sharing Plan Employer Contribution (\$)	Perquisites (a)	Total (\$)
Joseph W. Craft III	—	—	—
Cary P. Marshall	26,585	15,100	41,685
Steven C. Schnitzer	28,000	—	28,000
Kirk D. Tholen	28,000	—	28,000
Thomas M. Wynne	28,000	12,900	40,900

- a) For Mr. Marshall, perquisites and other personal benefits totaling \$15,100 comprise tax preparation fees of \$13,300 and other perquisites of \$1,800. For Mr. Wynne, perquisites and other personal benefits comprise tax preparation fees of \$12,900.

Grants of Plan-Based Awards Table

The following table sets forth information concerning grants of plan-based awards to each of our Named Executive Officers during fiscal year 2025.

Name	Grant Date	Approved Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Unit Awards: Number of Units (#)	Grant Date Fair Value of Unit Awards \$(5)
			Threshold \$(1)	Target \$(2)	Maximum \$(1)	Threshold #(3)	Target #(4)	Maximum #(3)		
Joseph W. Craft III										—
Cary P. Marshall	February 13, 2025	February 13, 2025					24,489			659,489
	January 28, 2025	January 27, 2026		303,000			—			—
				303,000			24,489			659,489
Steven C. Schnitzer	February 13, 2025	February 13, 2025					24,015			646,724
	January 28, 2025	January 27, 2026		272,500			—			—
				272,500			24,015			646,724
Kirk D. Tholen	February 13, 2025	February 13, 2025					28,784			775,153
	January 28, 2025	January 27, 2026		506,800			—			—
				506,800			28,784			775,153
Thomas M. Wynne	February 13, 2025	February 13, 2025					27,981			753,528
	January 28, 2025	January 27, 2026		506,800			—			—
				506,800			27,981			753,528

- (1) Awards under the STIP are subject to our achieving an annual financial performance target each year. However, determination of individual awards under the STIP is based on an assessment of the Named Executive Officer's performance, comparative compensation data of companies in our peer group and recommendation of the Chairman, President and CEO. The STIP does not specify any threshold or maximum payout amounts. Please see "Item 11. Compensation Discussion and Analysis—Compensation Components—*Annual Cash Incentive Bonus Awards*" for additional information regarding the STIP awards.
- (2) These amounts represent awards pursuant to our STIP. On January 28, 2025, the Compensation Committee set the EBITDA target amount for use in determining the total plan payout for 2025. The discretionary payout allocations to all participating employees are determined after the year is completed. Please see "Item 11. Compensation Discussion and Analysis—Compensation Components—*Annual Cash Incentive Bonus Awards*" for additional information regarding the STIP awards.
- (3) Grants of restricted units under our LTIP are generally not subject to minimum thresholds, targets or maximum payout conditions. However, the vesting of these grants is subject to the satisfaction of certain performance criteria. The

grants include a minimum value guarantee. Please see “Item 11. Compensation Discussion and Analysis—Compensation Components—*Equity Awards under the LTIP*.”

- (4) These awards are grants of restricted units pursuant to our LTIP. The grants include a minimum value guarantee. Please see “Item 11. Compensation Discussion and Analysis—Compensation Components—*Equity Awards under the LTIP*.”
- (5) We calculated the fair value of LTIP awards granted on February 13, 2025 to our Named Executive Officers using a value of \$26.93 per unit, the closing unit price on the grant date.

Narrative Disclosure Relating to the Summary Compensation Table and Grants of Plan-Based Awards Table

For a discussion regarding amounts payable pursuant to our STIP and LTIP, please see “Item 11. Compensation Discussion and Analysis—Compensation Components” above.

Schnitzer Employment Letter

We provided Mr. Schnitzer with his employment letter upon his entry into employment with us in 2024. The Schnitzer Employment Letter provides for, among other things, (i) an initial annual base salary of \$400,000, (ii) participation in our short-term incentive plan at 75% of annual base salary, (iii) an initial award in 2024 under the LTIP having value on the grant date of \$640,000, and (iv) a signing bonus of \$1.408 million, payable over eight quarters of \$184,000 for each of the first four quarters and \$168,000 for each of the last four quarters, in each case subject to Mr. Schnitzer’s continued employment through the applicable payment dates. The Schnitzer Employment Letter also provides for the payment of severance if Mr. Schnitzer’s employment is terminated on or before March 1, 2027 (as more fully described below within the section titled—*Potential Payments Upon a Termination or Change in Control*.”

Salary and Bonus in Proportion to Total Compensation

The following table shows the total of salary and bonus in proportion to total compensation from the Summary Compensation Table:

Name	Year	Salary and Bonus (\$)(1)	Total Compensation (\$)	Salary and Bonus as a % of Total Compensation (%) (1)
Joseph W. Craft III	2025	1	1	100.0%
Cary P. Marshall	2025	332,308	1,336,482	24.9%
Steven C. Schnitzer	2025	1,101,846	2,049,070	53.8%
Kirk D. Tholen	2025	555,385	1,865,338	29.8%
Thomas M. Wynne	2025	550,000	1,851,228	29.7%

- (1) Percentages were calculated using the base salary and bonus of the Named Executive Officers. The only bonus payments we provided to Named Executive Officers in 2025 were to Mr. Schnitzer, which consisted of four installments of his signing bonus pursuant to the Schnitzer Employment Letter.

Outstanding Equity Awards at 2025 Fiscal Year End Table

The following table reflects information regarding outstanding equity-based awards held by our Named Executive Officers as of December 31, 2025.

Name	Equity Incentive Plan Awards: Number of Unearned Units or Other Rights That Have Not Vested (#)(1)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Units or Other Rights That Have Not Vested (\$)(2)
Joseph W. Craft III	—	—
Cary P. Marshall	85,331	1,982,239
Steven C. Schnitzer	54,119	1,257,184
Kirk D. Tholen	95,790	2,225,202
Thomas M. Wynne	94,987	2,206,548

(1) Amounts represent restricted units awarded under the LTIP that were not vested as of December 31, 2025. Subject to our achieving financial performance targets, these units will vest as follows:

Name	January 1,		
	2026	2027	2028
Joseph W. Craft III	—	—	—
Cary P. Marshall	30,945	29,897	24,489
Steven C. Schnitzer	—	30,104	24,015
Kirk D. Tholen	34,080	32,926	28,784
Thomas M. Wynne	34,080	32,926	27,981

Please see “Item 11. Compensation Discussion and Analysis—Compensation Components—*Equity Awards under the LTIP*.” All grants of restricted units under the LTIP include the contingent right to receive quarterly cash distributions in an amount equal to the cash distributions we make to unitholders during the vesting period.

(2) Stated values are based on \$23.23 per unit, the closing price of our common units on December 31, 2025, the final market trading day of 2025.

Units Vested Table for 2025

The following table provides information, on an aggregate basis, about the Named Executive Officers' awards that vested during the fiscal year ended December 31, 2025. None of our Named Executive Officers hold any unit option awards.

Name	Unit Awards	
	Number of Units Acquired on Vesting (#)(1)	Value Realized on Vesting \$(1)
Joseph W. Craft III	—	—
Cary P. Marshall	29,173	766,958
Steven C. Schnitzer	—	—
Kirk D. Tholen	78,003	2,050,699
Thomas M. Wynne	54,602	1,435,487

(1) Amounts represent the number and value of restricted units granted under the LTIP that vested in 2025. All of these units vested on January 1, 2025 and are valued at \$26.29 per unit, the closing price on December 31, 2024, the final market trading day of 2024. Please see "Item 11. Compensation Discussion and Analysis—Compensation Components—*Equity Awards under the LTIP.*"

Potential Payments Upon a Termination or Change in Control

The following disclosures discuss the payments and benefits that each of our Named Executive Officers would have been eligible to receive upon certain termination events, assuming that each such termination occurred on December 31, 2025. As a result, the payments and benefits disclosed represent what would have been due to such Named Executive Officers under the applicable agreements and plans in existence as of December 31, 2025; this disclosure does not reflect any changes to such agreements or plans, or new agreements or plans adopted, after December 31, 2025, unless specifically stated.

Treatment of LTIP Awards upon a Change in Control

Each of our Named Executive Officers is eligible to receive accelerated vesting and payment under the LTIP upon certain terminations of employment or upon our change in control. Upon a "change in control," as defined in the LTIP, all outstanding awards under the LTIP will automatically vest and become payable or exercisable, as the case may be, in full. All restricted periods shall terminate and all performance criteria, if any, shall be deemed to have been achieved at the maximum level.

Under the LTIP, a "change in control" generally means, and will be deemed to have occurred upon the occurrence of one or more of the following events: (i) any sale, lease, exchange or other transfer of all or substantially all of the assets of the Partnership to any Person (as defined in the LTIP) or its affiliates, unless following the applicable transaction such assets are controlled, directly or indirectly, by Mr. Craft; (ii) the consolidation or merger of the Partnership with or into another Person pursuant to a transaction in which the outstanding voting interests of the Partnership are changed into or exchanged for cash, securities or other property, other than any such transaction where (a) the outstanding voting interests of the Partnership are changed into or exchanged for voting stock or interests of the surviving corporation or its parent, (b) the holders of the voting interests of the Partnership immediately prior to such transaction own, directly or indirectly, not less than a majority of the voting stock or interests of the surviving corporation or its parent immediately after such transaction, and (c) Mr. Craft, directly or indirectly, retains control over the business of the Partnership or any successor entity; or (iii) a "person" or "group" being or becoming the "beneficial owner" (such quoted terms as defined in the Exchange Act) of more than 50% of all voting interests of the Partnership then outstanding, other than (a) in a merger or consolidation which would not constitute a Change in Control under clause (ii) above or (b) any transaction in which Mr. Craft, directly or indirectly, retains control over the business of the Partnership or any successor entity.

Treatment of LTIP Awards upon a Termination of Employment (in connection with a Sale of Significant Assets)

Pursuant to the terms of the LTIP, in the event the Partnership sells or otherwise disposes of a significant portion of the assets under its control (as determined by action of the Board of Directors in its sole discretion), and as a result of such disposition (i) a participant's employment is terminated without "Cause" or by the participant for "Good Reason" as defined in the LTIP or (ii) the participant's employer will no longer be the Partnership or one of its affiliates, then all outstanding awards under the LTIP will automatically vest and become payable or exercisable, as the case may be, in full. All restricted periods shall terminate and all performance criteria, if any, shall be deemed to have been achieved at the maximum level; provided, however, that the restricted period may not terminate prior to the end of the "subordination period" (such quoted terms as defined in the LTIP). The subordination period has ended.

Termination of Employment under the Schnitzer Employment Letter

The Schnitzer Employment Letter provides that if Mr. Schnitzer's employment is terminated on or before March 1, 2027 (x) by us for any reason including a "Change of Control" but other than for "Cause" or (y) by Mr. Schnitzer for "Good Reason" (such quoted terms as defined in the Schnitzer Employment Letter), Mr. Schnitzer will receive a severance payment in an amount equal to (a) two times Mr. Schnitzer's then-effective annual base salary, plus (b) two times the then-effective standard payout for Mr. Schnitzer under the STIP, plus (c) any unpaid installment(s) of his signing bonus.

Except for the severance payments provided to Mr. Schnitzer under the Schnitzer Employment Letter, none of our Named Executive Officers were eligible for severance payments or change in control benefits outside of the potential equity award acceleration under the LTIP, as described above.

Quantification of Payments

The table below discloses the amount of compensation and/or benefits due to our Named Executive Officers in the event of their termination of employment and/or upon a change in control under their compensatory arrangements in effect on December 31, 2025. The actual amounts to be paid are dependent on various factors, which may or may not exist at the time a Named Executive Officer is actually terminated and/or a change in control actually occurs. All accelerated equity award values are calculated using a unit price of \$23.23 per unit, the closing price of our common units on December 31, 2025.

Name	Column (A)	Column (B)	Column (C)
	Benefits Payable Upon Termination without Cause or for Good Reason with a Sale of Significant Assets (\$ (1))	Benefits Payable Upon a Change in Control (No Termination) (\$)	Benefits Payable Upon Termination by Partnership for Any Reason (other than Cause) or by Employee for Good Reason (\$ (2))
Joseph W. Craft III			
Cash Payments	—	—	—
Accelerated Vesting of Equity	—	—	—
Total	—	—	—
Cary P. Marshall			
Cash Payments	—	—	—
Accelerated Vesting of Equity	1,982,238	1,982,238	—
Total	1,982,238	1,982,238	—
Steven C. Schnitzer			
Cash Payments	1,620,500	—	1,620,500
Accelerated Vesting of Equity	1,257,184	1,257,184	—
Total	2,877,684	1,257,184	1,620,500
Kirk D. Tholen			
Cash Payments	—	—	—
Accelerated Vesting of Equity	2,225,201	2,225,201	—
Total	2,225,201	2,225,201	—
Thomas M. Wynne			
Cash Payments	—	—	—
Accelerated Vesting of Equity	2,206,548	2,206,548	—
Total	2,206,548	2,206,548	—

(1) As set forth within the LTIP for all LTIP participants.

(2) This Column (C) does not include any amounts that could become payable upon an overlapping termination scenario that is already reflected within Column (A).

Director Compensation

The sole member of our general partner has the right to set the compensation of the directors of our general partner. Typically, such compensation has been set by the Compensation Committee with the concurrence of Mr. Craft, who indirectly owns our general partner. Mr. Craft, our only employee director, received no director compensation for 2025, and all compensation that Mr. Craft received in his capacity as an employee is set forth above within the Summary Compensation Table. The directors of MGP devote 100% of their time as directors of MGP to the business of the ARLP Partnership.

Director Compensation Table for 2025

The following table summarizes the compensation provided to the non-employee directors for the fiscal year ended December 31, 2025.

Name	Fees earned or Paid in Cash (\$)	Unit Awards (\$)(1)	Option Awards (\$)(1)	Non-Equity Incentive Plan Compensation (\$)(1)	Change in Pension Value and Nonqualified Deferred Compensation Earnings (\$)(1)	All Other Compensation (\$)(1)	Total (\$)
Nick Carter	\$ 225,000	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 225,000
Robert J. Druten	225,000	—	—	—	—	—	225,000
Ronna McDaniel	215,000	—	—	—	—	—	215,000
Wilson M. Torrence	245,000	—	—	—	—	—	245,000
Paul Vining	360,000	—	—	—	—	—	360,000

(1) Columns are not applicable to 2025 director compensation.

Narrative to Director Compensation Table

Compensation for our non-employee directors includes an annual cash retainer paid quarterly in advance on a pro rata basis. The annual retainer for 2025 was \$215,000. In addition to the retainer, Mr. Torrence was entitled to annual cash compensation in 2025 of \$30,000 for service as Chairman of the Audit Committee. Mr. Carter was entitled to additional annual cash compensation of \$10,000 for service as Chairman of the Compensation Committee. Mr. Druten was entitled to annual cash compensation in 2025 of \$10,000 for service as Chairman of the Conflicts Committee, and Mr. Vining was entitled to additional annual compensation of \$145,000 for his service as Lead Director of the Board of Directors.

CEO Pay Ratio Disclosures

As required by Section 953(b) of the Dodd-Frank Wall Street Reform and Consumer Protection Act, and Item 402(u) of Regulation S-K, we are providing the following information about the relationship of the annual total compensation of our employees and the annual total compensation of Joseph W. Craft III, our CEO.

For 2025, our last completed fiscal year:

- The median annual total compensation of all employees (other than the CEO) was \$104,552.
- The annual total compensation of our CEO, as reported in the Summary Compensation Table was \$1.
- Based on this information, for 2025 the ratio of the annual total compensation of our CEO to the median of the annual total compensation of all employees was reasonably estimated to be 0.00001 to 1.

To determine the annual total compensation of our median employee and our CEO, we took the following steps:

- Using the same median employee identified in 2023, we combined all of the elements of such employee's compensation for the 2025 year in accordance with the requirements of Item 402(c)(2)(x) of Regulation S-K, resulting in annual total compensation of \$104,552, comprised of such employee's W-2 compensation of \$97,712 and contributions in the amount of \$6,840 that we made on the employee's behalf to our 401(k) plan for the 2025 year.
- With respect to the annual total compensation of our CEO, we used the amount reported in the "Total" column of our 2025 Summary Compensation Table.

Compensation Committee Interlocks and Insider Participation

Mr. Craft, Chairman, President and CEO of our general partner, is also Chairman, President and CEO of AGP, which is the direct owner of 100% of the membership interests of our general partner. Otherwise, none of our executive officers serves as a member of the board of directors or compensation committee of any entity that has one or more of its executive officers serving as a member of the Board of Directors or Compensation Committee of our general partner.

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

The following table sets forth certain information as of February 17, 2026, regarding the beneficial ownership of common units held by (a) each director of our general partner, (b) each executive officer of our general partner identified in the Summary Compensation Table included in “Item 11. Executive Compensation” above, (c) all directors and executive officers as a group, and (d) each person known by our general partner to be the beneficial owner of more than 5% of our common units. The address of our general partner and, unless otherwise indicated in the footnotes to the table below, each of the directors, executive officers and more than 5% unitholders reflected in the table below is 1717 South Boulder Avenue, Suite 400, Tulsa, Oklahoma 74119. The percentage of common units beneficially owned is based on 128,658,801 common units outstanding as of February 17, 2026.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned
Directors and Executive Officers		
Joseph W. Craft III (1)	18,800,000	14.6%
Nick Carter	20,000	*
Robert J. Druten	25,628	*
Ronna McDaniel	—	*
Wilson M. Torrence	40,396	*
Paul Vining	—	*
Cary P. Marshall (2)	1,110,853	*
Steven C. Schnitzer	4,725	*
Kirk D. Tholen	172,657	*
Thomas M. Wynne (3)	1,333,281	1.0%
All directors and executive officers as a group (14 persons)	21,711,600	16.9%
More than 5% Common Unit Holder		
Kathleen Mowry	16,167,865	12.6%

* Less than one percent.

- (1) The common units attributable to Mr. Craft consist of (i) 18,631,398 common units held directly by him and (ii) 168,602 common units attributable to Mr. Craft’s spouse.
- (2) The common units attributable to Mr. Marshall consist of common units held through a trust and another entity controlled by him.
- (3) The common units attributable to Mr. Wynne consist of (i) 908,887 common units held directly by him and (ii) 424,394 common units held through a trust and another entity controlled by him.

Equity Compensation Plan Information

The following table sets forth certain information regarding our equity compensation plans as of December 31, 2025.

Plan Category	Number of units to be issued upon exercise/vesting of outstanding options, warrants and rights as of December 31, 2025	Weighted-average exercise price of outstanding options, warrants and rights	Number of units remaining available for future issuance under equity compensation plans as of December 31, 2025
Equity compensation plans approved by unitholders:			
Long-Term Incentive Plan	1,192,243	N/A	8,102,070

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

Omnibus Agreement

We are party to an omnibus agreement with MGP and AGP, which governs potential competition among us and the other parties to this agreement. Pursuant to the terms of the omnibus agreement, AGP and its affiliates agreed, for so long as Mr. Craft controls MGP, not to engage in the business of mining, marketing or transporting coal in the United States, unless it first offers us the opportunity to engage in a potential activity or acquire a potential business, and the Board of Directors, with the concurrence of its Conflicts Committee, elects to cause us not to pursue such opportunity or acquisition. In addition, AGP has the ability to purchase businesses, the majority value of which is not mining, marketing or transporting coal, provided AGP offers us the opportunity to purchase the coal assets following the acquisition. The restriction does not apply to the assets retained and business conducted by an affiliate of AGP at the closing of our initial public offering. Except as provided above, AGP and its affiliates are prohibited from engaging in activities wherein they compete directly with us.

Other Related-Party Transactions

In addition to the related-party policies and transactions discussed in “Item 8. Financial Statements and Supplementary Data — Note 1 — Organization and Presentation, Note 12 — Long-Term Debt and Note 21 — Related-Party Transactions” ARLP has the following additional related-party transactions:

Expense Reimbursements

Our partnership agreement provides that MGP and its affiliates be reimbursed for all direct and indirect expenses incurred or payments made on behalf of us, including, but not limited to, director fees and expenses. MGP may determine in its sole discretion the expenses that are allocable to us. Total costs billed to us by MGP and its affiliates were approximately \$1.3 million for the year ended December 31, 2025. The executive officers of MGP are employees of and paid by Alliance Coal, and the reimbursement we pay to MGP pursuant to the partnership agreement does not include any compensation expenses associated with them.

JC Land

Alliance Coal has a time-sharing agreement with JC Land concerning Alliance Coal’s use of aircraft owned by JC Land. In accordance with the provisions of that agreement, Alliance Coal paid JC Land \$0.5 million for the year ended December 31, 2025 for use of their aircraft.

Effective August 1, 2013, Alliance Coal entered into an expense reimbursement agreement with JC Land regarding pilots employed by Alliance Coal to operate aircraft owned by Alliance Service, Inc. and JC Land. In accordance with the expense reimbursement agreement, JC Land reimburses Alliance Coal for a portion of the compensation expense for its pilots. JC Land paid us \$0.4 million in 2025 pursuant to this agreement. Separately, JC Land paid us \$0.8 million during 2025 for fuel, pilot travel, etc. paid by us on their behalf.

Infinitum Electric, Inc.

On January 16, 2024, Matrix Design entered into an agreement with Infinitum to jointly develop and distribute high-efficiency motors and advanced motor controllers designed specifically for the mining industry. Matrix Design paid Infinitum \$0.9 million during the year and had no payable outstanding as of December 31, 2025 under this agreement.

Saminco Solutions LLC

Effective October 10, 2025, CR Services, LLC, a wholly owned subsidiary of the Partnership, entered into a Master Supply and Services Agreement with Saminco Solutions LLC (“Saminco”), an entity affiliated with Mr. Craft. This agreement provides for the purchase and servicing of electronic components and other parts used in mining equipment. The Partnership paid Saminco \$0.2 million during the year and had \$0.1 million payable as of December 31, 2025 under this agreement.

Director Independence

As a publicly traded limited partnership listed on the NASDAQ Global Select Market, we are required to maintain a sufficient number of independent directors on the board of our general partner to satisfy the audit committee requirement set forth in NASDAQ Rule 5605(c)(2)(A). Rule 5605(c)(2)(A) requires us to maintain an audit committee of at least three members, each of whom must, among other requirements, be independent as defined under NASDAQ Rule 5605(a)(2) and meet the criteria for independence set forth in Rule 10A-3(b)(1) under the Exchange Act (subject to the exemptions provided in Rule 10A-3(c)).

All members of the Audit and Compensation Committees—Messrs. Torrence, Carter, Druten and Ms. McDaniel—are independent directors as defined under applicable NASDAQ and Exchange Act rules. Please see “Item 10. Directors, Executive Officers and Corporate Governance of the General Partner—Audit Committee” and “Item 11. Executive Compensation—Compensation Discussion and Analysis.”

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The firm of Grant Thornton LLP is our independent registered public accounting firm for the 2025 year. The following table sets forth fees paid to Grant Thornton LLP during the years ended December 31, 2025 and 2024:

	2025	2024
	(in thousands)	
Audit Fees (1)	\$ 864	\$ 881
Audit-related fees (2)	129	135
Tax fees (3)	—	—
All other fees	—	13
Total	\$ 993	\$ 1,029

- (1) Audit fees consist primarily of the audit and quarterly reviews of the consolidated financial statements, but can also be related to statutory audits of subsidiaries required by governmental or regulatory bodies, attestation services required by statute or regulation, comfort letters, consents, assistance with and review of documents filed with the SEC, work performed by tax professionals in connection with the audit and quarterly reviews, and accounting and financial reporting consultations and research work necessary to comply with GAAP.
- (2) Audit-related fees consist primarily of attest services related to financial reporting that are not required by statute or regulation but can also include accounting consultations and audits in connections with acquisitions.
- (3) Tax fees consist primarily of services rendered for tax compliance, tax advice, and tax planning.

The charter of the Audit Committee provides that the committee is responsible for the pre-approval of all auditing services and permitted non-audit services to be performed for us by our independent registered public accounting firm, subject to the requirements of applicable law. In accordance with such charter, the Audit Committee may delegate the authority to grant such pre-approvals to the Audit Committee chairman or a sub-committee of the Audit Committee, which pre-approvals are then reviewed by the full Audit Committee at its next regular meeting. Typically, however, the Audit Committee itself reviews the matters to be approved. The Audit Committee periodically monitors the services rendered by and actual fees paid to the independent registered public accounting firm to ensure that such services are within the parameters approved by the Audit Committee.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) (1) Financial Statements and Supplementary Data.

	Page
Report of Independent Registered Public Accounting Firm (PCAOB ID Number 248)	96
Consolidated Balance Sheets	98
Consolidated Statements of Income	99
Consolidated Statements of Comprehensive Income	100
Consolidated Statements of Cash Flows	101
Consolidated Statement of Partners' Capital	102
Notes to Consolidated Financial Statements	103
1. Organization and Presentation	103
2. Summary of Significant Accounting Policies	104
3. Variable Interest Entities	113
4. Acquisitions	114
5. Fair Value Measurements	116
6. Inventories	118
7. Digital Assets	118
8. Property, Plant and Equipment	119
9. Long-Lived Asset Impairments	120
10. Investments	120
11. Leases	122
12. Long-Term Debt	123
13. Accrued Workers' Compensation and Pneumoconiosis Benefits	126
14. Employee Benefit Plans	128
15. Asset Retirement Obligations	132
16. Commitments and Contingencies	133
17. Partners' Capital	133
18. Common Unit-Based Compensation Plans	134
19. Revenue From Contracts With Customers	136
20. Concentration of Credit Risk and Major Customers	137
21. Related-Party Transactions	137
22. Income Taxes	139
23. Earnings Per Limited Partner Unit	141
24. Supplemental Cash Flow Information	142
25. Segment Information	142
26. Subsequent Event	145
Supplemental Oil & Gas Reserve Information (Unaudited)	146

(a)(2) Financial Statement Schedule.

Schedule I – Condensed Financial Information of Registrant	152
--	-----

All other schedules are omitted because they are not applicable or the information is shown in the financial statements or notes thereto.

(a)(3) and (c) The exhibits listed below are filed as part of this annual report.

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith*
		Form	SEC File No. and Film No.	Exhibit	Filing Date	
3.1	Amended and Restated Certificate of Limited Partnership of Alliance Resource Partners, L.P.	8-K	000-26823 17990766	3.6	07/28/2017	
3.2	Fourth Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P.	8-K	000-26823 17990766	3.2	07/28/2017	
3.3	Amendment No. 1 to the Fourth Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P.	10-K	000-26823 18634680	3.9	02/23/2018	
3.4	Amendment No. 2 to Fourth Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P., dated as of May 31, 2018.	8-K	000-26823 1883834	3.3	06/06/2018	
3.5	Amendment No. 3 to Fourth Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P., dated as of June 1, 2018.	8-K	000-26823 1883834	3.4	06/06/2018	
3.6	Certificate of Limited Partnership of Alliance Resource Operating Partners, L.P.	S-1/A	333-78845 99669102	3.8	07/23/1999	
3.7	First Amendment to Certificate of Limited Partnership of Alliance Resource Operating Partners, L.P.	10-Q	000-26823 241184062	3.7	08/07/2024	
3.8	Second Amendment to Certificate of Limited Partnership of Alliance Resource Operating Partners, L.P.	10-Q	000-26823 241184062	3.8	08/07/2024	
3.9	Third Amendment to Certificate of Limited Partnership of Alliance Resource Operating Partners, L.P.	10-Q	000-26823 241184062	3.9	08/07/2024	
3.10	Amended and Restated Agreement of Limited Partnership of Alliance Resource Operating Partners, L.P.	10-K	000-26823 583595	3.2	03/29/2000	
3.11	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Alliance Resource Operating Partners, L.P., dated as of May 31, 2018.	8-K	000-26823 1883834	3.5	06/06/2018	
3.12	Certificate of Formation of Alliance Resource Management GP, LLC	S-1/A	333-78845 99669102	3.7	07/23/1999	

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith*
		Form	SEC File No. and Film No.	Exhibit	Filing Date	
3.13	Third Amended and Restated Operating Agreement of Alliance Resource Management GP, LLC, dated as of May 31, 2018.	8-K	000-26823 1883834	3.7	06/06/2018	
3.14	Certificate of Formation of MGP II, LLC.	8-K	000-26823 17990766	3.5	07/28/2017	
3.15	Amended and Restated Operating Agreement of MGP II, LLC.	8-K	000-26823 17990766	3.4	07/28/2017	
4.1	Form of Common Unit Certificate (Included as Exhibit A to the Fourth Amended and Restated Agreement of Limited Partnership of Alliance Resource Partners, L.P., included in this Exhibit Index as Exhibit 3.2).	8-K	000-26823 17990766	3.2	07/28/2017	
4.2	Indenture, dated as of June 12, 2024, by and among Alliance Resource Operating Partners, L.P. and Alliance Resource Finance Corporation, as issuers, Alliance Resource Partners, L.P., as parent, the subsidiary guarantors party thereto and Computershare Trust Company, N.A., as trustee.	8-K	000-26823 241038800	4.1	06/12/2024	
4.3	Form of 8.625% Senior Note due 2029 (included in Exhibit 4.3).	8-K	000-26823 241038800	4.1	06/12/2024	
4.4	Description of the Registrant's Securities registered under Section 12 of the Securities Exchange Act of 1934.	10-K	000-26823 23666549	4.4	02/24/2023	
10.1	Omnibus Agreement, dated August 16, 1999, among Alliance Resource Holdings, Inc., Alliance Resource Management GP, LLC, Alliance Resource GP, LLC and Alliance Resource Partners, L.P.	10-K	000-26823 583595	10.4	03/29/2000	
10.2	Second Amendment to the Omnibus Agreement dated May 15, 2006 by and among Alliance Resource Partners, L.P., Alliance Resource GP, LLC, Alliance Resource Management GP, LLC, Alliance Resource Holdings, Inc., Alliance Resource Holdings II, Inc., AMH-II, LLC, Alliance Holdings GP, L.P., Alliance GP, LLC and Alliance Management Holdings, LLC	10-Q	000-26823 061017824	10.1	08/09/2006	
10.3 ⁽¹⁾	Alliance Coal, LLC Short-Term Incentive Plan	10-K	000-26823 583595	10.12	03/29/2000	
10.4 ⁽¹⁾	First Amendment to the Alliance Coal, LLC Short-Term Incentive Plan	10-K	000-26823 07660999	10.52	03/01/2007	

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith*
		Form	SEC File No. and Film No.	Exhibit	Filing Date	
10.5 ⁽¹⁾	Second Amendment to the Alliance Coal, LLC Short-Term Incentive Plan	10-K	000-26823 08654096	10.53	02/29/2008	
10.6 ⁽¹⁾	The Amended and Restated Alliance Coal, LLC Long-Term Incentive Plan as amended by the Third Amendment and Fourth Amendment	10-K	000-26823 161460619	10.46	02/26/2016	
10.7	Fifth Amendment to the Amended and Restated Alliance Coal, LLC 2000 Long-Term Incentive Plan.	8-K	000-26823 201385345	10.1	12/14/2020	
10.8	Sixth Amendment to the Amended and Restated Alliance Coal, LLC 2000 Long-Term Incentive Plan.	8-K	000-26823 221401012	10.1	11/18/2022	
10.9	Amended and Restated Administrative Services Agreement effective January 1, 2010, among Alliance Resource Partners, L.P., Alliance Resource Management GP, LLC, Alliance Resource Holdings II, Inc., Alliance Resource Operating Partners, L.P., Alliance Holdings GP, L.P. and Alliance GP, LLC.	10-Q	000-26823 101000555	10.1	08/09/2010	
10.10	Receivables Financing Agreement, dated as of December 5, 2014, among Borrower, PNC Bank, National Association, as administrative agent as well as the letter of credit bank, the persons from time to time party thereto as lenders, the persons from time to time party thereto as letter of credit participants, and Alliance Coal, LLC, as initial servicer	8-K	000-26823 141277053	10.3	12/10/2014	
10.11	First Amendment to the Receivables Financing Agreement, dated as of December 4, 2015	10-Q	000-26823 161634229	10.1	05/10/2016	
10.12	Second Amendment to the Receivables Financing Agreement, dated as of February 24, 2016	10-Q	000-26823 161634229	10.2	05/10/2016	
10.13	Third Amendment to the Receivables Financing Agreement, dated as of December 2, 2016	10-K	000-26823 17636362	10.45	02/24/2017	
10.14	Fourth Amendment to the Receivables Financing Agreement, dated as of November 27, 2017	10-K	000-26823 18634680	10.47	02/23/2018	
10.15	Fifth Amendment to the Receivables Financing Agreement, dated as of January 17, 2018	10-K	000-26823 18634680	10.48	02/23/2018	
10.16	Sixth Amendment to the Receivables Financing Agreement, dated as of June 19, 2018	10-Q	000-26823 18994075	10.2	08/06/2018	

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith*
		Form	SEC File No. and Film No.	Exhibit	Filing Date	
10.17	Seventh Amendment to the Receivables Financing Agreement, dated as of January 16, 2019	10-K	000-26823 19624803	10.52	02/22/2019	
10.18	Eighth Amendment to the Receivables Financing Agreement, dated as of October 22, 2019.	10-Q	000-26823 191192460	10.2	11/05/2019	
10.19	Ninth Amendment to the Receivables Financing Agreement, dated as of January 15, 2021.	10-K	000-26823 21663570	10.64	02/23/2021	
10.20	Tenth Amendment to the Receivables Financing Agreement, dated as of January 14, 2022.	10-K	000-26823 22677260	10.57	02/25/2022	
10.21	Eleventh Amendment to the Receivables Financing Agreement, dated as of January 13, 2023.	10-K	000-26823 23666549	10.54	02/24/2023	
10.22	Twelve Amendment to the Receivables Financing Agreement, dated as of April 21, 2023.	10-K	000-26823 25678699	10.24	02/27/2025	
10.23	Thirteenth Amendment to the Receivables Financing Agreement, dated as of January 12, 2024.	10-K	000-26823 24670765	10.30	02/23/2024	
10.24	Fourteenth Amendment to the Receivables Financing Agreement, dated as of January 10, 2025.	10-K	000-26823 25678699	10.26	02/27/2025	
10.25	Fifteenth Amendment to the Receivables Financing Agreement, dated as of January 9, 2026.					☒
10.26	Credit Agreement, dated as of January 13, 2023, among Alliance Coal, LLC, as borrower, Alliance Resource Operating Partners, L.P., Alliance Resource Partners, L.P., UC Coal, LLC, UC Mining, LLC, UC Processing, LLC and MGP II, LLC as additional Alliance entities and the initial lenders, initial issuing banks and swingline bank named therein, PNC Bank, National Association as administrative agent and collateral agent and PNC Capital Markets LLC, BOKF, NA DBA Bank of Oklahoma, Fifth Third Bank, National Association, Old National Bank and Trust Securities, Inc. as joint lead arrangers and joint bookrunners and the other institutions named therein as documentation agents.	8-K	000-26823 23540292	10.1	01/20/2023	

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith*
		Form	SEC File No. and Film No.	Exhibit	Filing Date	
10.27	Amendment No. 1, dated June 12, 2024, to the Credit Agreement, dated as of January 13, 2023, among Alliance Coal, LLC, as borrower, Alliance Resource Operating Partners, L.P., Alliance Resource Partners, L.P., UC Coal, LLC, UC Mining, LLC, UC Processing, LLC and MGP II, LLC as additional Alliance entities and the initial lenders, initial issuing banks and swingline bank named therein, PNC Bank, National Association as administrative agent and collateral agent and PNC Capital Markets LLC, BOKF, NA DBA Bank of Oklahoma, Fifth Third Bank, National Association, Old National Bank and Truist Securities, Inc. as joint lead arrangers and joint bookrunners and the other institutions named therein as documentation agents, arrangers and joint bookrunners and the other institutions named therein as documentation agents.	8-K	000-26823 241038800	10.1	06/12/2024	
10.28	Employment letter to Steven C. Schnitzer, dated February 26, 2024.	10-K	000-26823 25678699	10.29	02/27/2025	
10.29	Master Supply and Services Agreement dated as of October 10, 2025.	8-K	000-26823 251388654	10.1	10/10/2025	
10.30	Purchase and Sale Agreement dated January 29, 2026, by and between Alliance Resource Properties, LLC and The Joseph W. Craft III Foundation.	8-K	000-26823 26598830	10.1	02/04/2026	
10.31	Purchase and Sale Agreement dated January 29, 2026, by and between Alliance Resource Properties, LLC and The Kathleen S. Craft Foundation.	8-K	000-26823 26598830	10.2	02/04/2026	
19.1	Insider Trading Policy	10-K	000-26823 25678699	19.1	02/27/2025	
21.1	List of Subsidiaries.					☒
23.1	Consent of Grant Thornton LLP.					☒
23.2	Consent of Cawley, Gillespie & Associates, Inc.					☒
31.1	Certification of Joseph W. Craft III, President and Chief Executive Officer of Alliance Resource Management GP, LLC, the general partner of Alliance Resource Partners, L.P., dated February 26, 2026, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					☒

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith*
		Form	SEC File No. and Film No.	Exhibit	Filing Date	
31.2	Certification of Cary P. Marshall, Senior Vice President and Chief Financial Officer of Alliance Resource Management GP, LLC, the general partner of Alliance Resource Partners, L.P., dated February 26, 2026, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					☒
32.1	Certification of Joseph W. Craft III, President and Chief Executive Officer and Chairman of Alliance Resource Management GP, LLC, the general partner of Alliance Resource Partners, L.P., dated February 26, 2026, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					☒
32.2	Certification of Cary P. Marshall, Senior Vice President and Chief Financial Officer of Alliance Resource Management GP, LLC, the general partner of Alliance Resource Partners, L.P., dated February 26, 2026, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					☒
95.1	Federal Mine Safety and Health Act Information					☒
96.1	Henderson/Union Resources SEC S-K 1300 Technical Report Summary dated February 2024.	10-K	000-26823 24670765	96.1	02/23/2024	
96.2	River View Complex SEC S-K 1300 Technical Report Summary February 2024.	10-K	000-26823 24670765	96.2	02/23/2024	
96.3	Hamilton Mine SEC S-K 1300 Technical Report Summary dated February 2025.	10-K	000-26823 25678699	96.3	02/27/2025	
96.4	Gibson South Mine SEC S-K 1300 Technical Report Summary dated February 2022.	10-K/A	000-26823 221205681	96.4	08/26/2022	
96.5	Tunnel Ridge Mine SEC S-K 1300 Technical Report Summary dated February 2023.	10-K	000-26823 24670765	96.5	02/23/2024	
97.1	Alliance Resource Partners, L.P. Incentive Based Compensation Recoupment Policy	10-K	000-26823 24670765	97.1	02/23/2024	
99.1	Report of Cawley, Gillespie & Associates, Inc., dated January 15, 2026					☒
101	Interactive Data File (Form 10-K for the year ended December 31, 2025 filed in Inline XBRL).					☒
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).					☒

(1) Denotes management contract or compensatory plan or arrangement.

Signatures

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized, in Tulsa, Oklahoma, on February 26, 2026.

ALLIANCE RESOURCE PARTNERS, L.P.

By: Alliance Resource Management GP, LLC
its general partner

/s/ Joseph W. Craft III
Joseph W. Craft III
*President, Chief Executive
Officer and Chairman*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
<u>/s/ Joseph W. Craft III</u> Joseph W. Craft III	President, Chief Executive Officer, and Chairman (Principal Executive Officer)	February 26, 2026
<u>/s/ Cary P. Marshall</u> Cary P. Marshall	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 26, 2026
<u>/s/ Megan J. Cordle</u> Megan J. Cordle	Vice President, Controller and Chief Accounting Officer (Principal Accounting Officer)	February 26, 2026
<u>/s/ Nick Carter</u> Nick Carter	Director	February 26, 2026
<u>/s/ Robert J. Druten</u> Robert J. Druten	Director	February 26, 2026
<u>/s/ Ronna McDaniel</u> Ronna McDaniel	Director	February 26, 2026
<u>/s/ Wilson M. Torrence</u> Wilson M. Torrence	Director	February 26, 2026
<u>/s/ Paul H. Vining</u> Paul H. Vining	Director	February 26, 2026



**ALLIANCE RESOURCE
PARTNERS, L.P.**

P.O. Box 22027, Tulsa, Oklahoma 74121-2027 | www.arlp.com