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

FORM 10-Q

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

For the quarterly period ended September 30, 2025

OR

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

Commission file number:001-34743

HALLADOR ENERGY COMPANY
(www.halladorenergy.com**)**

Colorado	84-1014610
(State of incorporation)	(IRS Employer Identification No.)
1183 East Canvasback Drive, Terre Haute, Indiana	47802
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: 812.299.2800

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

Title of each class	Trading Symbol	Name of each exchange on which registered
Common Shares, $.01 par value	HNRG	Nasdaq

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 Regulations S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☑ No ☐

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

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

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

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

As of November 3, 2025, we had 43,825,006 shares of common stock outstanding.

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PART I - FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS

Hallador Energy Company
Condensed Consolidated Balance Sheets
(in thousands, except per share data)
(unaudited)

	September 30, 2025	December 31, 2024
ASSETS		
Current assets:		
Cash and cash equivalents	$ 12,663	$ 7,232
Restricted cash	22,819	4,921
Accounts receivable	24,763	15,438
Inventory	28,006	36,685
Parts and supplies	44,002	39,104
Prepaid expenses	4,293	1,478
Total current assets	136,546	104,858
Property, plant and equipment:		
Land and mineral rights	69,961	70,307
Buildings and equipment	454,040	429,857
Mine development	99,852	92,458
Finance lease right-of-use assets	13,034	13,034
Total property, plant and equipment	636,887	605,656
Less - accumulated depreciation, depletion and amortization	(370,903)	(347,952)
Total property, plant and equipment, net	265,984	257,704
Equity method investments	2,713	2,607
Other assets	4,218	3,951
Total assets	$ 409,461	$ 369,120
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Current portion of bank debt, net	$ 42,698	$ 4,095
Accounts payable and accrued liabilities	44,010	44,298
Current portion of lease financing	7,395	6,912
Contract liabilities - current	113,244	97,598
Total current liabilities	207,347	152,903
Long-term liabilities:		
Bank debt, net	—	37,394
Long-term lease financing	3,140	8,749
Asset retirement obligations	16,268	14,957
Contract liabilities - long-term	34,362	49,121
Other	2,156	1,711
Total long-term liabilities	55,926	111,932
Total liabilities	263,273	264,835
Commitments and contingencies (Note 16)		
Stockholders' equity:		
Preferred stock, $.10 par value, 10,000 shares authorized; none issued	—	—
Common stock, $.01 par value, 100,000 shares authorized; 42,978 and 42,621 issued and outstanding, as of September 30, 2025 and December 31, 2024, respectively	430	426
Additional paid-in capital	189,086	189,298
Retained deficit	(43,328)	(85,439)
Total stockholders' equity	146,188	104,285
Total liabilities and stockholders' equity	$ 409,461	$ 369,120

See accompanying notes to the condensed consolidated financial statements.

Hallador Energy Company
Condensed Consolidated Statements of Operations
(in thousands, except per share data)
(unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2025	2024	2025	2024
SALES AND OPERATING REVENUES:				
Electric sales	$ 93,235	$ 72,116	$ 239,154	$ 192,996
Coal sales	51,256	31,662	119,588	114,093
Other revenues	2,355	1,377	8,780	3,685
Total sales and operating revenues	146,846	105,155	367,522	310,774
EXPENSES:				
Fuel	27,119	13,755	57,392	34,684
Other operating and maintenance costs	44,415	32,741	101,759	103,704
Cost of purchased power	2,074	3,149	11,086	7,694
Utilities	4,543	3,586	13,202	12,090
Labor	27,574	26,721	81,402	88,444
Depreciation, depletion and amortization	9,142	13,838	29,661	42,930
Asset retirement obligations accretion	446	410	1,310	1,208
Exploration costs	38	62	157	179
General and administrative	4,770	6,471	19,096	20,218
Gain on disposal or abandonment of assets, net	(2,334)	(290)	(2,410)	(536)
Total operating expenses	117,787	100,443	312,655	310,615
INCOME FROM OPERATIONS	29,059	4,712	54,867	159
Interest expense (1)	(4,927)	(2,692)	(12,469)	(10,364)
Loss on extinguishment of debt	—	—	—	(2,790)
Equity method investment (loss)	(248)	(234)	(287)	(740)
NET INCOME (LOSS) BEFORE INCOME TAXES	23,884	1,786	42,111	(13,735)
INCOME TAX EXPENSE (BENEFIT):				
Current	—	—	—	—
Deferred	—	232	—	(3,389)
Total income tax expense (benefit)	—	232	—	(3,389)
NET INCOME (LOSS)	$ 23,884	$ 1,554	$ 42,111	$ (10,346)
NET INCOME (LOSS) PER SHARE:				
Basic	$ 0.56	$ 0.04	$ 0.98	$ (0.27)
Diluted	$ 0.55	$ 0.04	$ 0.97	$ (0.27)
WEIGHTED AVERAGE SHARES OUTSTANDING				
Basic	43,007	42,598	42,869	38,455
Diluted	43,434	43,018	43,287	38,455
(1) Interest Expense:				
Interest on bank debt	$ 1,763	$ 2,073	$ 4,661	$ 7,657
Other interest	2,585	181	6,208	1,456
Amortization of debt issuance costs	579	438	1,600	1,251
Total interest expense	$ 4,927	$ 2,692	$ 12,469	$ 10,364

See accompanying notes to the condensed consolidated financial statements.

Hallador Energy Company
Condensed Consolidated Statements of Cash Flows
(in thousands)
(unaudited)

	Nine Months Ended September 30,	
	2025	2024
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ 42,111	$ (10,346)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Deferred income tax (benefit)	—	(3,389)
Equity method investment loss	287	740
Depreciation, depletion and amortization	29,661	42,930
Loss on extinguishment of debt	—	2,790
Gain on disposal or abandonment of assets, net	(2,410)	(536)
Amortization of debt issuance costs	1,600	1,251
Asset retirement obligations accretion	1,310	1,208
Cash paid on asset retirement obligation reclamation	(455)	(820)
Stock-based compensation	2,144	3,320
Amortization of contract liabilities	(82,639)	(59,236)
Accretion on contract liabilities	5,659	—
Other	274	1,352
Change in current assets and liabilities:		
Accounts receivable	(9,325)	8,029
Inventory	8,679	(8,002)
Parts and supplies	(4,898)	(786)
Prepaid expenses	1,190	(1,098)
Accounts payable and accrued liabilities	1,923	(7,715)
Contract liabilities	77,867	57,293
Net cash provided by operating activities	72,978	26,985
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(44,277)	(39,606)
Proceeds from sale of equipment	2,891	3,373
Investment in equity method investments	(394)	—
Net cash used in investing activities	(41,780)	(36,233)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Payments on bank debt	(63,000)	(86,500)
Borrowings of bank debt	63,000	65,000
Payments on lease financing	(5,187)	(4,105)
Proceeds from sale and leaseback arrangement	—	3,783
Issuance of related party notes payable	—	5,000
Payments on related party notes payable	—	(5,000)
Debt issuance costs	(330)	(654)
ATM offering	—	34,515
Taxes paid on vesting of RSUs	(2,352)	(273)
Net cash (used in) provided by financing activities	(7,869)	11,766
Increase in cash, cash equivalents, and restricted cash	23,329	2,518
Cash, cash equivalents, and restricted cash, beginning of period	12,153	7,123
Cash, cash equivalents, and restricted cash, end of period	$ 35,482	$ 9,641
CASH, CASH EQUIVALENTS, AND RESTRICTED CASH:		
Cash and cash equivalents	$ 12,663	$ 3,829
Restricted cash	22,819	5,812
	$ 35,482	$ 9,641
SUPPLEMENTAL CASH FLOW INFORMATION:		
Cash paid for interest	$ 4,718	$ 8,679
SUPPLEMENTAL NON-CASH FLOW INFORMATION:		
Change in capital expenditures included in accounts payable and prepaid expense	$ (5,855)	$ (7,825)
Stock issued on redemption of convertible notes and interest	$ —	$ 22,993

See accompanying notes to the condensed consolidated financial statements.

Hallador Energy Company
Condensed Consolidated Statements of Stockholders' Equity
(in thousands)
(unaudited)

	Common Stock Issued		Additional Paid-in	Retained	Total Stockholders'
	Shares	Amount	Capital	Deficit	Equity
Balance, June 30, 2025	42,978	$ 430	$ 188,935	$ (67,212)	$ 122,153
Stock-based compensation	—	—	585	—	585
Stock issued on vesting of RSUs	64	1	(1)	—	—
Taxes paid on vesting of RSUs	(28)	(1)	(433)	—	(434)
Net Income	—	—	—	23,884	23,884
Balance, September 30, 2025	43,014	$ 430	$ 189,086	$ (43,328)	$ 146,188
Balance, December 31, 2024	42,621	$ 426	$ 189,298	$ (85,439)	$ 104,285
Stock-based compensation	—	—	2,144	—	2,144
Stock issued on vesting of RSUs	577	6	(6)	—	—
Taxes paid on vesting of RSUs	(184)	(2)	(2,350)	—	(2,352)
Net Income	—	—	—	42,111	42,111
Balance, September 30, 2025	43,014	$ 430	$ 189,086	$ (43,328)	$ 146,188

	Common Stock Issued		Additional Paid-in	Retained	Total Stockholders'
	Shares	Amount	Capital	Earnings	Equity
Balance, June 30, 2024	42,599	$ 426	$ 186,945	$ 128,799	$ 316,170
Stock-based compensation	—	—	1,073	—	1,073
Net income	—	—	—	1,554	1,554
Balance, September 30, 2024	42,599	$ 426	$ 188,018	$ 130,353	$ 318,797
Balance, December 31, 2023	34,052	$ 341	$ 127,548	$ 140,699	$ 268,588
Stock-based compensation	—	—	3,320	—	3,320
Stock issued on vesting of RSUs	379	4	(4)	—	—
Taxes paid on vesting of RSUs	(159)	(2)	(271)	—	(273)
Stock issued on redemption of convertible notes	3,672	36	22,957	—	22,993
Stock issued in ATM offering	4,655	47	34,468	—	34,515
Net loss	—	—	—	(10,346)	(10,346)
Balance, September 30, 2024	42,599	$ 426	$ 188,018	$ 130,353	$ 318,797

See accompanying notes to the condensed consolidated financial statements.

Hallador Energy Company
Notes to Condensed Consolidated Financial Statements
(unaudited)

(1) GENERAL BUSINESS

The condensed consolidated financial statements include the accounts of Hallador Energy Company (hereinafter known as "we, us, or our") and its wholly owned subsidiaries Hallador Power Company, LLC ("Hallador Power"), Sunrise Coal, LLC ("Sunrise"), and Hourglass Sands, LLC ("Hourglass"), as well as Hallador Power and Sunrise's wholly owned subsidiaries.

Our business is organized based on the services and products we provide in two segments: (i) Electric Operations and (ii) Coal Operations. The Chief Operating Decision Maker ("CODM"), who is the Company's Chief Executive Officer, reviews and assesses operating performance measures related to our Electric Operations and our Coal Operations segments.

In addition to these reportable segments, the Company has a "Corporate and Other and Eliminations" category, which is not significant enough, on a stand-alone basis, to be considered an operating segment. Corporate and Other and Eliminations primarily consist of unallocated corporate costs and activities, including a 50% interest in Sunrise Energy, LLC ("Sunrise Energy"), a private gas exploration company with operations in Indiana and Oaktown Gas, LLC, which we account for using the equity method.

The Electric Operations reportable segment includes electric power generation facilities of the Merom Power Plant ("Merom").

The Coal Operations reportable segment includes our currently operating underground mining complex Oaktown 1. We have other mining complexes and locations which were idled during the year ended December 31, 2024.

All significant intercompany accounts and transactions have been eliminated. Certain reclassifications have been made to the Company's prior period condensed consolidated financial information to conform to the current period presentation. These presentation changes did not impact the Company's condensed consolidated net income (loss), consolidated cash flows, total assets, total liabilities or total stockholders' equity.

The interim financial data is unaudited; however, in our opinion, it includes all adjustments, consisting only of normal recurring adjustments necessary for a fair statement of the results for the interim periods. The condensed consolidated financial statements included herein have been prepared pursuant to the Securities and Exchange Commission's (the "SEC") rules and regulations; accordingly, certain information and footnote disclosures normally included in generally accepted accounting principles ("GAAP") financial statements have been condensed or omitted.

The results of operations and cash flows for the three and nine months ended September 30, 2025, are not necessarily indicative of the results to be expected for future quarters or for the year ending December 31, 2025.

Our organization and business, the accounting policies we follow, and other information are contained in the notes to our consolidated financial statements filed as part of our 2024 Annual Report on Form 10-K. This quarterly report should be read in conjunction with such Annual Report on Form 10-K.

(2) RECENT ACCOUNTING PRONOUNCEMENTS

Recent Accounting Pronouncements - Adopted

For the year ended December 31, 2024, the Company retrospectively adopted Accounting Standards Update ("ASU") 2023-07, Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures ("ASU 2023-07"). See "*Note 14 – Segments of Business*" for enhanced disclosures associated with the adoption of ASU 2023-07.

Recent Accounting Pronouncements – Not Yet Adopted

In December 2023, the Financial Accounting Standards Board ("FASB") issued 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. ASU 2023-09 is effective for fiscal years beginning after December 15, 2024, with early adoption permitted. We are currently evaluating the impact of adopting ASU 2023-09, but do not expect it to have a material effect on our consolidated financial statements.

In November 2024, the FASB issued ASU 2024-04, Debt - Debt with Conversion and Other Options (Subtopic 470-20): Induced Conversion of Convertible Debt Instruments. The objective of the standard is to improve the relevance and consistency in application of the induced conversion guidance in Subtopic 470-20, Debt with Conversion and Other Options. This standard will affect entities that settle convertible debt instruments for which the conversion privileges are changed to induce conversion. The guidance will be effective for annual reporting periods beginning after December 15, 2025, and interim reporting periods within those annual reporting periods. The Company is currently evaluating the impact of the new standard on its financial statements and related disclosures.

In November 2024, the FASB issued ASU 2024-03, Income Statement Reporting-Comprehensive Income-Expense Disaggregation Disclosures (Subtopic 220-40): Disaggregation of Income Statement Expenses. The standard update improves the disclosures about a public business entity's expenses by requiring more detailed information about the types of expenses (including purchases of inventory, employee compensation, depreciation and amortization) included within income statement expense captions. The guidance will be effective for annual reporting periods beginning after December 15, 2026, and interim reporting periods beginning after December 15, 2027. Early adoption is permitted. The standard will be applied on a prospective basis, with retrospective application permitted. The Company is currently evaluating the impact of adoption of the standard on its financial statement disclosures.

(3) LONG-LIVED ASSET IMPAIRMENTS

During the year ended December 31, 2024, the Company recorded a $215.1 million non-cash impairment charge in our Coal Operations segment due to the results of our annual business plan review. As part of that business plan review, the Company evaluated core hole samples at several of our mines, noting the samples obtained at our Oaktown 2 mine were determined to be of a lower quality and density than that of the Oaktown 1 mine. As such, the Company decided to temporarily seal the Oaktown 2 mine, and to focus coal production at the Oaktown 1 mine, which has lower recovery costs.

The fair values of the impaired assets were determined using a discounted cash flow model, which represents Level 3 fair value measurements under the fair value hierarchy. The fair value analysis used assumptions regarding the projected economics of the Coal Operations assets, given prevailing commodity prices and operating expense levels.

For the three and nine months ended September 30, 2025, no impairment charges were recorded for long-lived assets.

(4) INVENTORY

Inventory is valued at a lower of cost or net realizable value ("NRV"). As of September 30, 2025, and December 31, 2024, coal inventory includes NRV adjustments of $0.1 million and $0.3 million, respectively. During the quarter, as part of the Company's routine inventory reconciliation process, a downward adjustment of $2.6 million was recorded to coal inventory.

(5) BANK DEBT

On June 27, 2025, the Company executed the Third Amendment ("Third Amendment") to the Fourth Amended and Restated Credit Agreement, dated as of August 2, 2023 (as amended, the "Credit Agreement"), with PNC Bank, National Association (in its capacity as administrative agent, "PNC"), which was accounted for as a debt modification. The primary purpose of the Third Amendment was to provide additional operating flexibility for the remainder of 2025 by redefining covenants, deferring certain covenants until the third quarter of 2025 and moving our October 2025 payment to January 2026. The Third Amendment provides for additional flexibility for the Company to enter into prepaid forward power sale contracts, provided that the Company maintains one hundred percent of the outstanding aggregate principal balance of the Credit Agreement ("Term Loan") as a compensating balance. During the second quarter of 2025, the Company entered into a $35.0 million prepaid forward power sales contract, as noted in "Note 7 – Revenue" of which $19.0 million of the proceeds were deposited into a money market account with the administrative agent. The compensating balance is classified as "restricted cash" on the condensed consolidated balance sheets at September 30, 2025. As part of the Third Amendment, the required October 2025 principal payment of $6.0 million and the January 2026 principal payment of $6.5 million, pursuant to the Term Loan, are both now due in January 2026. The balance of the Term Loan will be fully repaid no later than March 2026. All payments will be funded by withdrawals from our compensating balance held in our money market account. Furthermore, the Third Amendment defines certain administrative changes which include, among other things modifications to the required timelines related to reporting and the removal of third-party financial advisors.

On a net basis, bank debt did not change during the nine months ended September 30, 2025. Bank debt totaled $44.0 million as of September 30, 2025 and is comprised of our Term Loan ($19.0 million as of September 30, 2025) and a $75.0 million revolver ($25.0 million borrowed as of September 30, 2025) under the Credit Agreement. Our debt is recorded at amortized cost, which approximates fair value due to the variable interest rates in the agreement and is collateralized primarily by our assets.

Liquidity

As of September 30, 2025, we had additional borrowing capacity of $33.8 million under the revolver and total liquidity of $46.4 million. Our additional borrowing capacity is net of $16.2 million in outstanding letters of credit as of September 30, 2025 that were required to maintain surety bonds and other credit support obligations. Liquidity consists of our additional borrowing capacity and unrestricted cash and cash equivalents.

The Company is currently in discussions with members of its existing bank group and other lenders to refinance our current Credit Agreement. The revolving credit facility matures August 2, 2026 and our Term Loan matures March 31, 2026. The balance of the Term Loan is scheduled to be repaid in January 2026 and March 2026, utilizing restricted cash as set forth in the Third Amendment. As such, our revolving credit facility and Term Loan are listed as current on the September 30, 2025 condensed consolidated balance sheets. While no definitive agreement has been reached as of the reporting date, management believes it is probable that the Credit Agreement will be refinanced on market terms and conditions for similarly situated borrowers and consistent with the existing Credit Agreement. However, there can be no assurance that such efforts will be successful or completed on favorable terms. Failure to refinance our Credit Agreement debt prior to maturity could adversely affect the Company's liquidity and financial condition.

Fees

Unamortized bank fees and other costs incurred in connection with our initial facility totaled $4.3 million. Additional costs incurred with our Debt Agreement amendments totaled $0.9 million, of which $0.3 million related to our Third Amendment. These unamortized bank fees were deferred and are being amortized over the term of the loan. Unamortized bank fees as of September 30, 2025, and December 31, 2024, were $1.3 million and $2.5 million, respectively. Unused borrowing capacity under the facility was $33.8 million as of September 30, 2025. Commitment fees on the unused portion of the facility are 0.50% per annum.

Bank debt, less debt issuance costs, is presented below (in thousands):

	September 30, 2025	December 31, 2024
Current bank debt	$ 44,000	$ 6,000
Less unamortized debt issuance cost	(1,302)	(1,905)
Net current portion	$ 42,698	$ 4,095
Long-term bank debt	$ —	$ 38,000
Less unamortized debt issuance cost	—	(606)
Net long-term portion	$ —	$ 37,394
Total bank debt	$ 44,000	$ 44,000
Less total unamortized debt issuance cost	(1,302)	(2,511)
Net bank debt	$ 42,698	$ 41,489

Future Maturities (in thousands):	
2025	$ —
2026	44,000
Total	$ 44,000

Covenants

The Third Amendment, among other things, deferred the Maximum Leverage Ratio and Minimum Debt Service Coverage Ratios until September 2025. The Maximum Leverage Ratio requirement was changed to 3.00 to 1.00 for our fiscal quarter ending September 30, 2025, and is 2.25 to 1.00 thereafter. The Debt Service Coverage Ratio requirement was changed to 3.25 to 1.00 as long as the Company maintains the required compensating balance, if not, remains at 1.25 to 1.00. The Third Amendment removed the First Lien Leverage Ratio (as defined in the First Amendment to the Credit Agreement) while maintaining the minimum liquidity requirement of $10.0 million.

As of September 30, 2025, we were in compliance with all covenants defined in the Credit Agreement.

Interest Rate

The interest rate on the facility ranges from secured overnight financing rate ("SOFR") plus 4.00% to SOFR plus 5.00%, depending on our Leverage Ratio. As of September 30, 2025, we were paying SOFR plus 5.00% on the outstanding bank debt which equates to an all-in rate of 9.27%.

(6) ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

Accounts payable and accrued liabilities consist of the following for the indicated dates (in thousands):

	September 30, 2025	December 31, 2024
Accounts payable	$ 23,272	$ 24,291
Accrued property taxes	4,337	4,185
Accrued payroll	4,655	3,258
Workers' compensation reserve	5,408	4,321
Group health insurance	1,500	1,700
Asset retirement obligation - current portion	1,397	1,952
Other	3,441	4,591
Total accounts payable and accrued liabilities	$ 44,010	$ 44,298

(7) REVENUE

Revenue from Contracts with Customers

We account for a contract with a customer when the parties have executed the contract and are committed to performing their respective obligations, the rights of each party are identified, payment terms are identified, the contract has commercial substance, and it is probable substantially all the consideration will be collected. We recognize revenue when we satisfy a performance obligation by transferring control of a good or service to a customer.

Electric operations

We concluded that for a Power Purchase Agreement ("PPA") that is not determined to be a lease or derivative, the definition of a contract and the criteria in ASC 606, Revenue from Contracts with Customers ("ASC 606"), is met at the time a PPA is executed by the parties, as this is the point at which enforceable rights and obligations are established. Accordingly, we concluded that a PPA that is not determined to be a lease or derivative constitutes a valid contract under ASC 606.

We recognize revenue daily, based on an output method of capacity made available as part of any stand-ready obligations for contract capacity performance obligations and daily, based on an output method of MWh of electricity delivered.

For the delivered energy performance obligation in the PPA with Hoosier, we recognize revenue daily for actual delivered electricity plus the amortization of the contract liability as a result of the Asset Purchase Agreement with Hoosier. For delivered energy to all other customers, we recognize revenue daily for the actual delivered electricity.

When energy hours at the Merom Hub are priced below our production cost or during outages at Merom, we have the option to make net hourly purchases of power in the MISO market. We record these as "cost of purchased power" on our condensed consolidated statements of operations.

Coal operations

Our coal revenue is derived from sales to customers of coal produced at our facilities. Our customers typically purchase coal directly from our mine sites where the sale occurs and where title, risk of loss, and control pass to the customer at that point. Our customers arrange for and bear the costs of transporting their coal from our mines to their plants or other specified discharge points. Our customers are typically domestic utility companies. Our coal sales agreements with our customers are fixed-priced, fixed-volume supply contracts, or include a pre-determined escalation in price for each year. Price re-opener and index provisions may allow either party to commence a renegotiation of the contract price at a pre-determined time. Price re-opener provisions may automatically set a new price based on the prevailing market price or, in some instances, require us to negotiate a new price, sometimes within specified ranges of prices. The terms of our coal sales agreements result from competitive bidding and extensive negotiations with customers. Consequently, the terms of these contracts vary by customer.

Coal sales agreements will typically contain coal quality specifications. With coal quality specifications in place, the raw coal sold by us to the customer at the delivery point must be substantially free of magnetic material and other foreign material impurities and crushed to a maximum size as set forth in the respective coal sales agreement. Price adjustments are made and billed in the month the coal sale was recognized based on quality standards that are specified in the coal sales agreement, such as Btu factor, moisture, ash, and sulfur content, and can result in either increases or decreases in the value of the coal shipped.

Disaggregation of Revenue

Revenue is disaggregated by revenue source for our Electric Operations and by primary geographic markets for our Coal Operations, as we believe this best depicts how the nature, amount, timing, and uncertainty of our revenue and cash flows are affected by economic factors.

Electric Operations

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2025	2024	2025	2024
Delivered energy (including contract liability amortization)	$ 77,776	$ 56,256	$ 194,044	$ 148,490
Capacity	15,459	15,860	45,110	44,506
Total Electric Operations sales	$ 93,235	$ 72,116	$ 239,154	$ 192,996

Coal Operations

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2025	2024	2025	2024
Outside third-party Indiana customers	$ 27,355	$ 13,338	$ 68,960	$ 46,490
Customers in Florida, North Carolina, Alabama and Georgia	23,901	18,324	50,628	67,603
Total Coal Operations sales	$ 51,256	$ 31,662	$ 119,588	$ 114,093

Performance Obligations

Electric Operations

We concluded that each megawatt hour ("MWh") of delivered energy is capable of being distinct as a customer could benefit from each on its own by using/consuming it as a part of its operations. We also concluded that the stand-ready obligation to be available to provide electricity is capable of being distinct as each unit of capacity provides an economic benefit to the holder and could be sold by the customer.

During the second quarter of 2025, we entered into a 17-month, $35.0 million prepaid physically delivered power contract with energy to be delivered at various periods starting in July 2025 through November 2026. During the third quarter of 2025, we entered into a 5-month, $20.0 million prepaid physically delivered power contract with energy to be delivered January 2027 through May 2027. As the total amounts paid upfront by the customers differ from the stand-alone selling price of the transferred power, the Company concluded the contracts contain a significant financing component. The contract liabilities associated with the prepayments will be accreted over the agreement term based upon the Company's incremental borrowing rates at the time of the contract which approximates 9.50% and 9.92% for the respective contracts, and the accretion is separately recognized as interest expense.

Coal Operations

A performance obligation is a promise in a contract with a customer to provide distinct goods or services. Performance obligations are the unit of account for purposes of applying the revenue recognition standard and therefore determine when and how revenue is recognized. In most of our coal contracts, the customer contracts with us to provide coal that meets certain quality criteria. We consider each ton of coal a separate performance obligation and allocate the transaction price based on the base price per the contract, increased or decreased for quality adjustments.

The following table illustrates the balance of all current Electric and Coal Operations contracts allocated to performance obligations that are unsatisfied or partially unsatisfied as of September 30, 2025 and disaggregated by segment and contract duration.

	2025	2026	2027	2028	2029	Total
Delivered energy revenues	$ 43,780	$ 172,360	$ 117,300	$ 57,700	$ 13,860	$ 405,000
Capacity revenues	12,980	61,540	51,400	37,330	3,470	166,720
Coal Operations revenues (1)	27,070	151,560	141,850	29,500	—	349,980
Total revenue	$ 83,830	$ 385,460	$ 310,550	$ 124,530	$ 17,330	$ 921,700

(1) Coal revenues consist of consolidated revenues excluding our intercompany revenues from Merom.

Contract Balances

Under ASC 606, the timing of when a performance obligation is satisfied can affect the presentation of accounts receivable, contract assets and contract liabilities. The main distinction between accounts receivable and contract assets is whether consideration is conditional on something other than the passage of time. A receivable is an entity's right to consideration that is unconditional.

Under the typical payment terms of our contracts with customers, the customer pays us the contracted price for electricity or capacity. For coal contracts, the customer pays us a base price for the coal, increased or decreased for any quality adjustments. Amounts billed and due are recorded as trade accounts receivable and included in accounts receivable in our condensed consolidated balance sheets. Payments received prior to fulfilling our performance obligations are included in contract liabilities in our condensed consolidated balance sheets.

The following table shows our beginning and ending accounts receivable from contracts with customers balance for the periods presented (in thousands):

	September 30,	
	2025	2024
Accounts receivable from contracts with customers - beginning balance	$ 15,438	$ 19,937
Accounts receivable from contracts with customers - ending balance	$ 24,763	$ 11,908

As the Company fulfills its contractual obligations, we recognized those amounts in revenues. The following table reconciles our beginning and ending contract liabilities for the periods presented (in thousands):

	September 30,	
	2025	2024
Total contract liabilities - beginning balance	$ 146,719	$ 113,741
Cash payments received on future contract obligations	102,480	90,082
Accretion on contract liabilities	5,659	—
Revenue recognized, cash payment received in prior period	(82,639)	(59,236)
Revenue recognized, cash payment received in current period	(24,613)	(32,789)
Total contract liabilities - ending balance	$ 147,606	$ 111,798

(8) INCOME TAXES

For the nine months ended September 30, 2025 and 2024, we recorded income taxes using an estimated annual effective tax rate based upon projected annual income (loss), forecasted permanent tax differences, discrete items, and statutory rates in states in which we operate. The effective tax rate for the nine months ended September 30, 2025 and 2024, was ~ 0% due to recording of a full valuation allowance and ~24%, respectively. Historically, our actual effective tax rates have differed from the statutory effective rate primarily due to the benefit received from statutory percentage depletion in excess of tax basis. The deduction for statutory percentage depletion does not necessarily change proportionately to changes in income (loss) before income taxes.

On July 4, 2025, H.R.1, commonly referred to as the One Big Beautiful Bill Act ("OBBBA") was enacted. The OBBBA includes a broad range of tax reform provisions affecting businesses, including extending and modifying certain key Tax Cuts & Jobs Act provisions (both domestic and international), expanding certain Inflation Reduction Act incentives, and accelerating the phase-out of or repealing others. We have analyzed the provisions within the act and determined that the benefits relating to capital expenditures and deductibility of interest under IRC Section 163(j) will provide cash flow benefits to the company in 2025 by accelerating deductions for tax purposes. As the material benefits relate to the timing of deductions, there were no material impact affecting the effective tax rate or the valuation allowance determination in the third quarter of 2025.

(9) STOCK COMPENSATION PLANS

Non-vested grants as of December 31, 2024	1,034,486
Awarded	355,258
Vested	(577,101)
Forfeited	(14,500)
Non-vested grants as of September 30, 2025	798,143

For the three and nine months ended September 30, 2025, our stock compensation expense was $0.6 million and $2.1 million, respectively. For the three and nine months ended September 30, 2024, our stock compensation expense was $1.1 million and $3.3 million, respectively.

Non-vested RSU grants will vest as follows:

Vesting Year	RSUs Vesting
2025	156,000
2026	225,714
2027	405,213
2028	11,216
	798,143

As noted in our Form 8-K filed with the SEC on June 2, 2025, on May 29, 2025, shareholders approved the Second Amended and Restated 2008 Restricted Stock Unit Plan (the "RSU Plan") which, (i) increased the number of shares available for issuance by 2,000,000 shares, and (ii) extended the term of the RSU Plan until May 29, 2035.

As of September 30, 2025, unrecognized stock compensation expense to be recognized over the rolling 3-year vesting period is $6.4 million, and we had 1,897,154 RSUs available for future issuance. RSUs are not allocated earnings and losses as they are considered non-participating securities. Forfeitures are recognized as they occur.

(10) SELF-INSURANCE

The Company is self-insured for certain risks, including physical damage and operational liability, related to our non-leased underground mining equipment allocated among four mining units dispersed over seven miles. The Company records a liability for self-insured risks when a loss is both probable and reasonably estimable. The Company had no accrual for self-insurance liabilities as of September 30, 2025 or December 31, 2024.

The Company also self-insures for workers' compensation claims under a guaranteed cost program. Under this program, the Company is responsible for the first $1.0 million per claim up to an aggregate of $4.0 million annually. The Company has restricted cash of $22.8 million and $4.9 million as of September 30, 2025, and December 31, 2024, respectively, which represents cash held and controlled by third parties and is restricted primarily for future workers' compensation claim payments and the $19.0 million compensating balance on our Term Loan (as discussed in "Note 5 – Bank Debt" above). The Company had $5.4 million and $4.3 million of workers' compensation reserve as of September 30, 2025 and December 31, 2024, respectively, in "accounts payable and accrued liabilities" on the condensed consolidated balance sheets.

(11) FAIR VALUE MEASUREMENTS

We account for certain assets and liabilities at fair value. The hierarchy below lists three levels of fair value based on the extent to which inputs used in measuring fair value are observable in the market. We categorize each of our fair value measurements in one of these three levels based on the lowest level input that is significant to the fair value measurement in its entirety. These levels are:

Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. We consider active markets as those in which transactions for the assets or liabilities

occur in sufficient frequency and volume to provide pricing information on an ongoing basis. We have no Level 1 instruments.

Level 2: Quoted prices in markets that are not active, or inputs that are observable, either directly or indirectly, for substantially the full term of the asset or liability. We have no Level 2 instruments.

Level 3: Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little or no market activity). ARO liabilities use Level 3 non-recurring fair value measures.

Nonrecurring Fair Value Measurements

During the fourth quarter of 2024, the Company completed its review of the coal mining facilities and future mining plans. The impairment analysis was based upon the coal mining operating plans of the Company, market driven pricing and cost trends. As part of that analysis, the Company determined the carrying amount of its coal mining long-lived asset group was not recoverable and recorded a non-cash, long-lived asset impairment charge of $215.1 million in 2024.

The discounted cash flow model was calculated using projected economics for the Coal Operations assets, using the Company's mining plan and reserve estimates to be mined and sold at prevailing commodity prices, operating expenses, and production cost levels, which are classified as Level 3 inputs.

Credit Risk

The Company's financial instruments exposed to concentrations of credit risk consist primarily of cash and cash equivalents, and restricted cash.

The Company's cash and cash equivalent and restricted cash balances on deposit with financial institutions total $35.5 million and $12.2 million as of September 30, 2025 and December 31, 2024, respectively, which exceeded FDIC insured limits. The Company regularly monitors these institutions' financial condition. The Company utilizes large and reputable banking institutions which it believes mitigates these risks. The Company has not experienced any losses in such accounts.

(12) EQUITY METHOD INVESTMENTS

We own a 50% interest in Sunrise Energy, LLC, which owns gas reserves and gathering equipment with plans to develop and operate such reserves. Sunrise Energy, LLC, also plans to develop and explore for oil, natural gas, and coal-bed methane gas reserves on or near our underground coal reserves. The carrying value of the investment included in our condensed consolidated balance sheets as of September 30, 2025, and December 31, 2024, was $2.0 million and $2.1 million, respectively.

The Company also owns a 50% interest in Oaktown Gas, LLC. Oaktown Gas, LLC operates an emission abatement project through the destruction of gases extracted from the Oaktown mines to generate carbon credits and other emissions offset credits. The carrying value of the investment included in the condensed consolidated balance sheets as of September 30, 2025, and December 31, 2024, was $0.7 million and $0.5 million, respectively.

(13) ORGANIZATIONAL RESTRUCTURING

On February 23, 2024, (the "Effective Date"), we committed to a reorganization effort in the Coal Operations Segment (the "Reorganization Plan") that included a workforce reduction of approximately 110 employees, or approximately 12% of the workforce. The reduction in workforce was communicated to employees on the Effective Date and implemented immediately, subject to certain administrative procedures. The Reorganization Plan was designed to strengthen our financial and operational efficiency and create significant operational savings and higher margins in our Coal Operations segment. This step helped advance our transition from a company primarily focused on coal production to a more resilient and diversified integrated independent power producer ("IPP"). As part of this initiative, we substantially idled production at our higher cost surface mines, Prosperity Mine and Freelandville Mine, with minimal

ongoing production. We also focused our seven units of underground equipment on four units of our lowest cost production at our Oaktown Mine. In connection with the Reorganization Plan, we incurred aggregate expenses of $1.9 million ($1.1 million in the first quarter of 2024 and $0.8 million in the second quarter of 2024) that were included in "labor" in the condensed consolidated statements of operations. These charges related to compensation, tax, professional, and insurance related expenses are considered one-time charges paid during 2024. The coal mining properties asset group was tested for impairment as result of the organizational restructuring passing the undiscounted recoverability test.

(14) SEGMENTS OF BUSINESS

Our business is organized based on the services and products we provide in two segments: (i) Electric Operations and (ii) Coal Operations. The CODM, who is the Company's Chief Executive Officer, reviews and assesses operating performance measures related to our Electric Operations and our Coal Operations segments.

Our Electric Operations segment includes the electric power generation facilities of our Merom power plant, which is a two unit, 1080-megawatt rated coal fired power plant located in Sullivan County, Indiana. Our sales region is in MISO Zone 6, which includes Indiana and a portion of western Kentucky. Revenues from our Electric Operations segment consist primarily of delivered energy and capacity revenues. Fuel costs included in our Electric Operations segment include the cost of coal purchased from our Coal Operations segment, which are based on multi-year contracts which approximate market prices at the time the contracts are entered into.

Our Coal Operations segment includes the Oaktown 1 underground mining complex, as well as other currently idled mining facilities, which produce high-quality bituminous coal from the Illinois Basin. Revenues from our Coal Operations segment consist of sales of coal to various third-parties and to Merom. Coal sales to our Electric Operations are based on multi-year contracts which approximate market prices at the time the contracts are entered into. Intercompany coal sales and amounts above actual costs to produce the coal are eliminated in the consolidated statements of operations.

In addition to these reportable segments, the Company has a "Corporate and Other and Eliminations" category, which is not significant enough, on a stand-alone basis, to be considered an operating segment. Corporate and Other and Eliminations primarily consist of unallocated corporate costs and activities, including our equity method investments.

The CODM evaluates segment performance based upon EBITDA margin for each business segment. EBITDA margin is calculated for each segment as follows:

1. For our Electric Operations segment, EBITDA margin is comprised of delivered energy revenues less certain significant segment expenses, which include (i) variable costs are comprised of fuel costs and certain other operating costs, such as limestone and soda ash, (ii) other operating and maintenance costs, (iii) costs of purchased power, (iv) utilities, (v) labor and (vi) general and administrative costs.

2. For our Coal Operations segment, EBITDA margin is comprised of coal sales less certain significant segment expenses, which include (i) fuel, (ii) other operating and maintenance costs, (iii) utilities, (iv) labor and (v) general and administrative costs.

EBITDA margin for each segment is a key measure used by our CODM and provides information about our core operating performance, significant expenses and ability to generate cash flow. Additionally, EBITDA margin provides investors with the financial analytical framework upon which our CODM bases financial, operational, compensation and planning decisions and presents a measurement that investors, rating agencies and debt holders have indicated is useful in assessing us and our results of operations. Our CODM reviews variable costs, as defined above, in our Electric Operations segment in order to evaluate the efficiency of that segments operations.

Presented below are the Electric and Coal Operations key metrics reviewed by the CODM for the three months ended September 30, 2025 (in thousands):

	Electric Operations		Coal Operations
Delivered Energy	$ 77,776	Coal Sales	$ 68,814
Capacity Revenue	15,459		
Electric Sales	$ 93,235		
Fuel	$ (44,751)		
Other Operating Costs (1)	(1)		
Total Variable Costs	$ (44,752)		
Other Operating and Maintenance Costs (2)	$ (9,368)	Fuel	$ (574)
Cost of Purchased Power	(2,074)	Other Operating and Maintenance Costs	(35,046)
Utilities	(1,873)	Utilities	(2,670)
Labor	(7,949)	Labor	(19,625)
Power Margin Without General and Administrative	27,219	Coal Margin Without General and Administrative	10,899
General and Administrative	(1,308)	General and Administrative	(2,062)
Electric Operations — EBITDA Margin	$ 25,911	Coal Operations — EBITDA Margin	$ 8,837

(1) Other operating costs primarily include costs for lime dust.
(2) Other operating and maintenance costs include all other operating and maintenance costs with the exceptions of those costs considered variable as discussed above in (1).

Presented below are the Electric and Coal Operations key metrics reviewed by the CODM for the three months ended September 30, 2024 (in thousands):

	Electric Operations		Coal Operations
Delivered Energy	$ 56,256	Coal Sales	$ 48,320
Capacity Revenue	15,860		
Electric Sales	$ 72,116		
Fuel	$ (30,181)		
Other Operating Costs (1)	(36)		
Total Variable Costs	$ (30,217)		
Other Operating and Maintenance Costs (2)	$ (5,561)	Fuel	$ (572)
Cost of Purchased Power	(3,149)	Other Operating and Maintenance Costs	(27,031)
Utilities	(492)	Utilities	(3,094)
Labor	(7,360)	Labor	(19,361)
Power Margin Without General and Administrative	25,337	Coal Margin Without General and Administrative	(1,738)
General and Administrative	(1,252)	General and Administrative	(2,082)
Electric Operations — EBITDA Margin	$ 24,085	Coal Operations — EBITDA Margin	$ (3,820)

(1) Other operating costs primarily include costs for lime dust.
(2) Other operating and maintenance costs include all other operating and maintenance costs with the exceptions of those costs considered variable as discussed above in (1).

Presented below are the Electric and Coal Operations key metrics reviewed by the CODM for the nine months ended September 30, 2025 (in thousands):

	Electric Operations		Coal Operations
Delivered Energy	$ 194,044	Coal Sales	$ 169,117
Capacity Revenue	45,110		
Electric Sales	$ 239,154		
Fuel	$ (104,150)		
Other Operating Costs (1)	(10)		
Total Variable Costs	$ (104,160)		
Other Operating and Maintenance Costs (2)	$ (24,602)	Fuel	$ (1,564)
Cost of Purchased Power	(11,086)	Other Operating and Maintenance Costs	(77,147)
Utilities	(3,932)	Utilities	(9,270)
Labor	(23,731)	Labor	(57,671)
Power Margin Without General and Administrative	71,643	Coal Margin Without General and Administrative	23,465
General and Administrative	(3,972)	General and Administrative	(6,290)
Electric Operations — EBITDA Margin	$ 67,671	Coal Operations — EBITDA Margin	$ 17,175

(1) Other operating costs primarily include costs for lime dust.
(2) Other operating and maintenance costs include all other operating and maintenance costs with the exceptions of those costs considered variable as discussed above in (

Presented below are the Electric and Coal Operations key metrics reviewed by the CODM for the nine months ended September 30, 2024 (in thousands):

	Electric Operations		Coal Operations
Delivered Energy	$ 148,490	Coal Sales	$ 160,066
Capacity Revenue	44,506		
Electric Sales	$ 192,996		
Fuel	$ (79,532)		
Other Operating Costs (1)	(22)		
Total Variable Costs	$ (79,554)		
Other Operating and Maintenance Costs (2)	$ (22,926)	Fuel	$ (2,557)
Cost of Purchased Power	(7,694)	Other Operating and Maintenance Costs	(80,419)
Utilities	(1,451)	Utilities	(10,639)
Labor	(22,203)	Labor	(66,241)
Power Margin Without General and Administrative	59,168	Coal Margin Without General and Administrative	210
General and Administrative	(3,760)	General and Administrative	(8,012)
Electric Operations — EBITDA Margin	$ 55,408	Coal Operations — EBITDA Margin	$ (7,802)

(1) Other operating costs primarily include costs for lime dust.
(2) Other operating and maintenance costs include all other operating and maintenance costs with the exceptions of those costs considered variable as discussed above in (

Presented below are the Electric and Coal Operations revenues reconciled to our consolidated operating revenues for the three months ended September 30, 2025 (in thousands):

Reconciliation of Revenue:	Electric Operations	Coal Operations	Corporate and Other and Eliminations	Consolidated
Delivered Energy	$ 77,776	$ —	$ —	$ 77,776
Capacity Revenue	15,459	—	—	15,459
Other Revenue	192	1,647	516	2,355
Coal Sales (Third-Party)	—	51,256	—	51,256
Coal Sales (Intercompany)	—	17,558	(17,558)	—
Operating Revenues	$ 93,427	$ 70,461	$ (17,042)	$ 146,846

Presented below are the Electric and Coal Operations revenues reconciled to our consolidated operating revenues for the three months ended September 30, 2024 (in thousands):

Reconciliation of Revenue:	Electric Operations	Coal Operations	Corporate and Other and Eliminations	Consolidated
Delivered Energy	$ 56,256	$ —	$ —	$ 56,256
Capacity Revenue	15,860	—	—	15,860
Other Revenue	187	721	469	1,377
Coal Sales (Third-Party)	—	31,662	—	31,662
Coal Sales (Intercompany)	—	16,658	(16,658)	—
Operating Revenues	$ 72,303	$ 49,041	$ (16,189)	$ 105,155

Presented below are the Electric and Coal Operations revenues reconciled to our consolidated operating revenues for the nine months ended September 30, 2025 (in thousands):

Reconciliation of Revenue:	Electric Operations	Coal Operations	Corporate and Other and Eliminations	Consolidated
Delivered Energy	$ 194,044	$ —	$ —	$ 194,044
Capacity Revenue	45,110	—	—	45,110
Other Revenue	3,413	4,370	997	8,780
Coal Sales (Third-Party)	—	119,588	—	119,588
Coal Sales (Intercompany)	—	49,529	(49,529)	—
Operating Revenues	$ 242,567	$ 173,487	$ (48,532)	$ 367,522

Presented below are the Electric and Coal Operations revenues reconciled to our consolidated operating revenues for the nine months ended September 30, 2024 (in thousands):

Reconciliation of Revenue:	Electric Operations	Coal Operations	Corporate and Other and Eliminations	Consolidated
Delivered Energy	$ 148,490	$ —	$ —	$ 148,490
Capacity Revenue	44,506	—	—	44,506
Other Revenue	518	2,028	1,139	3,685
Coal Sales (Third-Party)	—	114,093	—	114,093
Coal Sales (Intercompany)	—	45,973	(45,973)	—
Operating Revenues	$ 193,514	$ 162,094	$ (44,834)	$ 310,774

Presented below is our reconciliation of EBITDA Margin to the most comparable GAAP account, income (loss) before income taxes for the three months ended September 30, 2025 (in thousands):

Reconciliation of Income (Loss) before Income Taxes:	Electric Operations	Coal Operations	Corporate and Other and Eliminations	Consolidated
Electric Operations — EBITDA Margin	$ 25,911	$ —	$ 18,206	$ 44,117
Coal Operations — EBITDA Margin	—	8,837	(17,558)	(8,721)
Other Operating Revenue	192	1,647	516	2,355
Depreciation, Depletion and Amortization	(5,131)	(3,992)	(19)	(9,142)
Asset Retirement Obligations Accretion	(126)	(320)	—	(446)
Exploration Costs	—	(38)	—	(38)
Gain (loss) on disposal or abandonment of assets, net	—	2,334	—	2,334
Interest Expense	(2,585)	(2,342)	—	(4,927)
Equity Method Investment (Loss)	—	—	(248)	(248)
Corporate — General and Administrative	—	—	(1,400)	(1,400)
Income (Loss) before Income Taxes	$ 18,261	$ 6,126	$ (503)	$ 23,884

Presented below is our reconciliation of EBITDA Margin to the most comparable GAAP account, income (loss) before income taxes for the three months ended September 30, 2024 (in thousands):

Reconciliation of Income (Loss) before Income Taxes:	Electric Operations	Coal Operations	Corporate and Other and Eliminations	Consolidated
Electric Operations — EBITDA Margin	$ 24,085	$ —	$ 16,998	$ 41,083
Coal Operations — EBITDA Margin	—	(3,820)	(16,658)	(20,478)
Other Operating Revenue	187	721	469	1,377
Depreciation, Depletion and Amortization	(4,802)	(9,013)	(23)	(13,838)
Asset Retirement Obligations Accretion	(115)	(295)	—	(410)
Exploration Costs	—	(62)	—	(62)
Gain (loss) on disposal or abandonment of assets, net	—	290	—	290
Interest Expense	(181)	(2,511)	—	(2,692)
Loss on Extinguishment of Debt	—	—	—	—
Equity Method Investment (Loss)	—	—	(234)	(234)
Corporate — General and Administrative	—	—	(3,136)	(3,136)
Corporate — Other Operating and Maintenance Costs	—	—	(114)	(114)
Income (Loss) before Income Taxes	$ 19,174	$ (14,690)	$ (2,698)	$ 1,786

Presented below is our reconciliation of EBITDA Margin to the most comparable GAAP account, income (loss) before income taxes for the nine months ended September 30, 2025 (in thousands):

Reconciliation of Income (Loss) before Income Taxes:	Electric Operations	Coal Operations	Corporate and Other and Eliminations	Consolidated
Electric Operations — EBITDA Margin	$ 67,671	$ —	$ 48,322	$ 115,993
Coal Operations — EBITDA Margin	—	17,175	(49,529)	(32,354)
Other Operating Revenue	3,413	4,370	997	8,780
Depreciation, Depletion and Amortization	(15,456)	(14,148)	(57)	(29,661)
Asset Retirement Obligations Accretion	(369)	(941)	—	(1,310)
Exploration Costs	—	(157)	—	(157)
Gain (loss) on disposal or abandonment of assets, net	—	2,410	—	2,410
Interest Expense	(6,208)	(6,261)	—	(12,469)
Equity Method Investment (Loss)	—	—	(287)	(287)
Corporate — General and Administrative	—	—	(8,834)	(8,834)
Income (Loss) before Income Taxes	$ 49,051	$ 2,448	$ (9,388)	$ 42,111

Presented below is our reconciliation of EBITDA Margin to the most comparable GAAP account, income (loss) before income taxes for the nine months ended September 30, 2024 (in thousands):

Reconciliation of Income (Loss) before Income Taxes:	Electric Operations	Coal Operations	Corporate and Other and Eliminations	Consolidated
Electric Operations — EBITDA Margin	$ 55,408	$ —	$ 47,405	$ 102,813
Coal Operations — EBITDA Margin	—	(7,802)	(45,973)	(53,775)
Other Operating Revenue	518	2,028	1,139	3,685
Depreciation, Depletion and Amortization	(14,197)	(28,671)	(62)	(42,930)
Asset Retirement Obligations Accretion	(339)	(869)	—	(1,208)
Exploration Costs	—	(179)	—	(179)
Gain (loss) on disposal or abandonment of assets, net	—	536	—	536
Interest Expense	(515)	(8,908)	(941)	(10,364)
Loss on Extinguishment of Debt	—	—	(2,790)	(2,790)
Equity Method Investment (Loss)	—	—	(740)	(740)
Corporate — General and Administrative	—	—	(8,446)	(8,446)
Corporate — Other Operating and Maintenance Costs	—	—	(337)	(337)
Income (Loss) before Income Taxes	$ 40,875	$ (43,865)	$ (10,745)	$ (13,735)

Presented below are our Electric and Coal Operations assets and capital expenditures for the periods presented below (in thousands):

Other Reconciliations:	Electric Operations	Coal Operations	Corporate and Other and Eliminations	Consolidated
Assets at September 30, 2025	$ 233,865	$ 153,514	$ 22,082	$ 409,461
Assets at December 31, 2024	$ 220,477	$ 144,519	$ 4,124	$ 369,120
Capital Expenditures at September 30, 2025	$ 25,369	$ 18,908	$ —	$ 44,277

Presented below are our Electric and Coal Operations assets and capital expenditures for the periods presented below (in thousands):

Other Reconciliations:	Electric Operations	Coal Operations	Corporate and Other and Eliminations	Consolidated
Assets at September 30, 2024	$ 217,826	$ 357,913	$ 3,991	$ 579,730
Assets at December 31, 2023	$ 208,331	$ 376,387	$ 5,062	$ 589,780
Capital Expenditures at September 30, 2024	$ 16,121	$ 23,002	$ 483	$ 39,606

(15) NET INCOME (LOSS) PER SHARE

The following table (in thousands, except per share amounts) sets forth the computation of basic earnings (loss) per share for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2025	2024	2025	2024
Basic earnings per common share:				
Net income (loss) - basic	$ 23,884	$ 1,554	$ 42,111	$ (10,346)
Weighted average shares outstanding - basic	43,007	42,598	42,869	38,455
Basic earnings (loss) per common share	$ 0.56	$ 0.04	$ 0.98	$ (0.27)

The following table (in thousands, except per share amounts) sets forth the computation of diluted net income (loss) per share:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2025	2024	2025	2024
Diluted earnings per common share:				
Net income (loss) - diluted	$ 23,884	$ 1,554	$ 42,111	$ (10,346)
Weighted average shares outstanding - basic	43,007	42,598	42,869	38,455
Add: Dilutive effects of Restricted Stock Units	427	420	418	—
Weighted average shares outstanding - diluted	43,434	43,018	43,287	38,455
Diluted net income (loss) per share	$ 0.55	$ 0.04	$ 0.97	$ (0.27)

(16) CONTINGENCIES

Our Coal Operations subsidiary is party to litigation 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. In January 2025, we agreed to settle with the plaintiffs such litigation for $2.8 million, which was recorded in “operating expenses” on our consolidated statements of operations for the year ended December 31, 2024. During the third quarter of 2025, $2.7 million was transferred into an escrow account while the settlement is pending court approval of the settlement terms. At September 30, 2025, $0.1 million related to the settlements remains in “accounts payable and accrued liabilities” on our condensed consolidated balance sheets at September 30, 2025.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

THE FOLLOWING DISCUSSION UPDATES THE MD&A SECTION OF OUR 2024 ANNUAL REPORT ON FORM 10-K AND SHOULD BE READ IN CONJUNCTION THEREWITH.

We are pleased with our favorable results in the third quarter, during which time we generated $146.8 million of revenue with $23.9 million of net income, representing substantial improvement over the $105.2 million of revenue with $1.6 million of net income generated in the prior year period. For the nine months ended September 30, 2025, we generated $367.5 million of revenue with $42.1 million of net income both materially above prior year performance.

Traditional summer weather patterns coupled with higher energy demand and higher natural gas prices provided for a supportive energy-pricing environment during the quarter that led to higher revenue at our Hallador Power subsidiary. Following the completion of Unit 2's annual maintenance outage in early July 2025, both units operated very well throughout the quarter. We also saw positive results in our Coal Operations resulting from solid coal production, increased shipments and consistent operating costs. The favorable power markets led to increased dispatch levels at both Merom and customer plants, which provided a boost to coal shipments and helped to decrease coal inventories at both the power plant and the mine.

During the third quarter 2025 , the Company entered into a $20.0 million prepaid forward power sales contract with scheduled deliveries throughout the first half of 2027. As we have previously noted, these firm forward sales allow us to improve liquidity from lower future price environments and also provides an advantage, as we saw in this instance, when pricing is stronger. These prepaid sales help us to lock in prices in the near term as we continue to focus on securing a long-term power purchase agreement in support of utility, data center and/or other large scale industrial development. The prepaid funds will be used to support company operations and capital expenditures.

We continue to see significant and accelerating interest in our capacity and energy offerings. As the third quarter progressed, we saw increased activity from both data center developers and load serving entities seeking the scarce inventory of large blocks of capacity and energy that we have available in the coming decade. We are in advanced discussions on both fronts and anticipate making positive progress towards a long-term agreement with a data center developer or load serving entity by early 2026. Each of the interested parties brings a unique perspective to the negotiations and each presents differentiated value creation opportunities and challenges to effectively monetize our capacity and energy offerings. We continue to believe that the evolving energy markets, specifically related to data center growth and favorable load serving entity demand, as well as the newly supportive regulatory environment, are providing us with opportunities that were not available when we began the request for proposal process. We also recognize that these opportunities have an undefined lifespan and we continue to work diligently to secure an agreement that will benefit the Company and our shareholders, both now and in the future.

While we still believe that an agreement with a load serving entity is intrinsically more straightforward to negotiate, can be implemented sooner and could result in greater sales volumes of energy and accredited capacity, we are beginning to see improving timelines on the developer side, especially where the developers had the foresight to speculatively acquire required infrastructure, such as step-down transformers, switch gear and other site-specific level electrical equipment. We anticipate favorable pricing in these potential opportunities, but, as we have highlighted before, data center arrangements are inherently more complex and involve multiple parties, which by its nature adds time and alignment challenges to the negotiation process. Notwithstanding those challenges, returning to non-exclusive negotiations reinforced our belief that we will forge a strategic partnership and create significant value for years to come.

Throughout the past several years, we have expressed our strong belief that the prevailing industry trend of retiring dispatchable generators in favor of non-dispatchable resources, such as wind and solar, will create and has created an unbalanced supply and demand equation, resulting in reduced availability and increased price of accredited capacity. It is our position that the enhanced reliability of dispatchable generation, like Merom, versus non-dispatchable generators will increase the value of the attributes of Hallador Power in the overall energy markets. With this in mind, we continue to evaluate the potential to enhance value through strategic growth initiatives such as the acquisition of retiring or retired generation assets and infrastructure. We are regularly evaluating potential acquisition opportunities to diversify and

increase our dispatchable generation as well as other strategic opportunities, which we believe would inherently diversify our generation portfolio, and provide an avenue to realize future growth opportunities. We believe that this approach has the potential to enhance our financial flexibility and strengthen our position in the evolving energy market.

We remain optimistic about the potential to add to our strategic generation portfolio and the long-term benefits that such a transaction could produce for the company, its shareholders and its customers. This model for growth enables us to capture value by providing accredited capacity and reliable energy. In connection with this belief, on November 3, 2025, Hallador Power submitted an application to MISO's Expedited Resource Addition Study (ERAS) program to add an additional 525 MW of gas generation at the Merom site. Given the strong market signals that we are currently seeing for our product offerings and the robust interest in the types of long-term arrangements that we are currently evaluating, we believe that it is an appropriate time to explore increasing generation at Merom. While the application is only a first step in our growth process and does not guarantee that we will be able to add the full load which we applied for, or any additional generation as part of ERAS, we are excited to participate in the opportunity and for what it could mean to the future of Hallador. We are currently targeting the generation to come online late in 2028. The process is capital intensive and includes operational, financial, regulatory and legal risks that could impact the project's viability and/or timeline.

Additionally, we see the potential of enhancing Merom's reliability, resiliency and flexibility by incorporating natural gas and creating a dual fuel configuration should operational and financial conditions support it. While we remain in the evaluation process, by adding the capability to co-fire with gas or coal, we believe that it could provide Hallador Power and its customers the ability to take advantage of economic fluctuations in fuel cost and provide potential flexibility as we manage other operating expenses. We believe that the ability to co-fire with natural gas and coal will also provide increased resiliency in times where gas availability is limited and allow us to retain the economic advantages of operating our Sunrise Coal subsidiary and leveraging our own fuel supply to ensure competitively priced offerings from third party fuel providers. This evaluation is complex on a variety of levels, specifically customer preference and an evolving regulatory environment, each of which could materially impact the timing and economic benefits of undertaking such a change.

In 2024, we delivered 2.9 million MWh of energy during the first nine months at an average sales price of $50.97 per MWh. In 2025, we delivered 4.0 million MWh of energy during the first nine months at an average sales price of $48.88. As illustrated in the forward sales position table, below, following 2026, we are optimistic that we will be able to sell energy at higher prices in support of data center development and/or to traditional wholesale customers in line with the indicators of a strong forward energy pricing curve.

Shifting to our Coal Operations, during the quarter, we saw improvements in operational expenses and increased shipments. The improved dispatch levels at Merom and our customers' plants helped to reduce our previously elevated inventories, while still allowing us adequate fuel inventory to position us well to meet industry needs if power plants, including Merom, dispatch at higher levels over the course of the upcoming Winter season.

With renewed support of coal mining and coal fired generation on both the federal and state level, we believe that we are well-positioned to take advantage of opportunities for strategic growth and/or organic expansion. We believe that current market dynamics remain stronger than they were in the past year, and we are actively assessing the timing and feasibility of expanding coal production in 2026. As we have previously said, our average contracted sales price in 2026 across all coal sales contracts is approximately $4.00 per ton higher than the average contracted sales price in 2025.

We currently expect to produce approximately 3.8 million tons of coal in 2025. In the first three quarters of 2025, we produced 3.1 million tons of coal at our Oaktown Mining Complex. We also use supplemental coal from third party suppliers at Merom, typically purchased at favorable prices to help diversify self-production supply risk and to provide us with additional flexibility in our ability to rapidly respond to customer demand if spot market pricing justifies doing so. This optionality to obtain low-cost fuel either internally or from third-parties while capturing upward swings in the commodity markets for coal should allow us to further maximize margins while optimizing fuel costs at Merom.

The continued transformation of Hallador from a commodity focused producer of coal to a vertically integrated IPP remains our primary focus. This allows us to leverage the ongoing impacts of the energy transition to capture the

expanding margins of the energy markets and capitalize on the rising demand for reliable electricity. As described above, we continue to see very strong interest from data center developers and load serving entities with respect to our energy and accredited capacity offerings. This interest and the number of inquiries accelerated throughout the quarter and we are encouraged by the variety of interested parties and the varied deal structures that we are seeing with respect to our offerings. We continue to believe that our business is well positioned to take advantage of opportunities for growth and cash flow generation as they arise.

Like our competitors, Hallador's business is affected by various macroeconomic factors, including tariffs and inflationary trends. The U.S. has implemented, or is considering implementing, higher tariffs on imports into the U.S. While such tariffs could potentially result in reduced economic activity, increased costs in operating our business including potential supply chain disruptions, and changes in purchasing behaviors for thermal coal or other potentially adverse economic outcomes, tariffs (or retaliatory trade measures imposed by other countries on U.S. goods) have not yet had a significant impact on our business or results of operations.

Our goal is for Hallador Power to generate up to 6.0 million MWh annually (see Hallador Power's capacity and utilization information below), if the markets and energy pricing support that level of generation. During the first nine months of the year, Hallador Power generated approximately 3.7 million MWh, or roughly 82.0% of our year-to-date target and economically purchased 0.3 million MWh.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2025	2024	2025	2024
Power Capacity and Utilization				
Nameplate capacity (MW)[(i)]	1,080	1,080	1,080	1,080
Accredited capacity for the period (MW)[(ii)]	748	828	821	858
Accredited capacity utilization[(iii)]	93 %	59 %	69 %	47 %

(i). Nameplate capacity for the Merom Power Plant refers to the maximum electric output generated by the plant in the period presented and may not reflect actual production. Actual production each period varies based on weather conditions, operational conditions, and other factors.

(ii). Accredited capacity is based on MISO's average seasonal accreditations for the year. Average seasonal accreditations were 775 MW and 829 MW per day for 2025 and 2024, respectively. Accreditations are weighted and adjusted annually based on 3-year rolling performance metrics.

(iii). Accredited capacity utilization is measured as power produced (MWh) divided by accredited capacity for the period (MW) multiplied by 24, times the number of days for the period.

When forward selling Capacity, we target annual sales of around $65.0 million to offset our fixed annual costs at the plant of approximately $60.0 million. For 2025, we have contracted approximately $58.1 million or 89.4% of our target. We believe our forward Capacity sales goals are attainable as illustrated in our "Forward Sales Position" table below.

Our condensed consolidated financial statements should be read in conjunction with this discussion. This analysis includes a discussion of metrics on a per mega-watt hour (MWh) and a per ton basis as derived from the condensed consolidated financial statements, which are considered non-GAAP measurements. These metrics are significant factors in assessing our operating results and profitability.

OVERVIEW

The following is an overview our Electric Operations and Coal Operations results for Q3 2025 compared to Q2 2025.

I. Q3 2025 Net Income of $23.9 million.

a. Electric Operations:

i. In Q3 2025, Total Electric Sales were $93.2 million, or $59.09 per MWh sold, an increase of $33.2 million or 55.3% from Q2 2025.

ii. In Q3 2025, Total Electric Operations expenses on a segment basis were $75.2 million or $47.64 per MWh sold an increase of $23.7 million or 46.0% from Q2 2025.

iii. Q3 2025 Electric Operations net income was $18.3 million an increase of $6.7 million or 57.8% from Q2 2025.

Key drivers in Q3 2025 Electric Operations results were:

(1) During the third quarter of 2025, we sold 1.6 million MWh representing a 100.0% increase in total MWh sold from the second quarter of 2025. This increase was expected as Q2 2025 typically has lower demand for power and we had a planned maintenance outage on one of our units at Merom for approximately two months during the second quarter. On a per MWh basis, Q3 Electrics Sales were $59.09 per MWh sold compared to $72.44 per MWh sold in Q2 2025. The variance on a per MWh basis was primarily due to the allocation of capacity revenue over increased energy volumes.

(2) In Q3 2025, significant operating costs including fuel, other operating and maintenance and cost of purchased power were $56.2 million, or $35.61 per MWh compared to $34.2 million, or $41.31 per MWh in Q2 2025. The increase in costs reflect the higher plant output and planned maintenance as also reflected in the decreased cost per MWh from Q2.

(3) Q3 2025 Electric Operations income before income taxes was $18.3 million or $11.57 per MWh, an increase of $6.7 million and a decrease of $2.42 per MWh from Q2 2025.

b. Coal Operations:

i. In Q3 2025, Total Coal Sales on a segment basis were $68.8 million, or $50.79 per ton sold, an increase of $23.3 million or 51.2% from Q2 2025.

ii. In Q3 2025, Total Coal Operations Expenses on a segment basis were $66.7 million, or $49.20 per ton sold, an increase of $21.1 million or 46.3% from Q2 2025.

iii. Q3 2025 Coal Operations Net Income on a segment basis was $6.1 million an increase of 335.7% from Q2 2025.

Key drivers in Q3 2025 Coal Operations results were:

(1) In Q3 2025, tons sold were 1.4 million tons on a segment basis at an average price per ton of $50.79, with approximately 0.3 million tons of that being shipped to Merom for $17.6 million compared to 0.9 million tons sold in Q2 2025 at an average price of $51.16, with approximately 0.1 million tons of that being shipped to Merom for $7.4 million. This increase was expected as Q2 is the shoulder season and typically has lower demand for coal at both Merom and third-party customers.

(2) In Q3 2025, Other operating and maintenance costs were $35.0 million, or $25.86 per ton, compared to $18.2 million, or $20.50 per ton, on a segment basis, in Q2 2025. This increase is mainly attributable to an increase of sales related royalties of $3.0 million and an increase of $14.9 million in coal cost of sales directly related to the increase in sales.

(3) Q3 2025 Coal Operations income before income taxes was $6.1 million or $4.53 per ton on a segment basis. This is an increase of $4.7 million or $2.95 per ton from Q2 2025.

II. Forward Sales Position (unaudited)*

	Q4 2025	2026	2027	2028	2029	Total
Power						
Energy						
Contracted MWh (in millions)	1.15	4.00	2.31	1.09	0.27	8.82
Average contracted price per MWh	$ 38.07	$ 43.09	$ 50.78	$ 52.94	$ 51.33	
Contracted revenue (in millions)	$ 43.78	$ 172.36	$ 117.30	$ 57.70	$ 13.86	$ 405.00
Capacity						
Average daily contracted capacity MW	668	733	623	454	100	
Average contracted capacity price per MWd	$ 211	$ 230	$ 226	$ 225	$ 230	
Contracted capacity revenue (in millions)	$ 12.98	$ 61.54	$ 51.40	$ 37.33	$ 3.47	$ 166.72
Total Energy & Capacity Revenue						
Contracted Power revenue (in millions)	$ 56.76	$ 233.90	$ 168.70	$ 95.03	$ 17.33	$ 571.72
Coal						
Priced tons - 3rd party (in millions)	0.51	2.72	2.50	0.50	—	6.23
Avg price per ton - 3rd party	$ 53.08	$ 55.72	$ 56.74	$ 59.00	$ —	
Contracted coal revenue - 3rd party (in millions)	$ 27.07	$ 151.56	$ 141.85	$ 29.50	$ —	$ 349.98
TOTAL CONTRACTED REVENUE (IN MILLIONS) - CONSOLIDATED	$ 83.83	$ 385.46	$ 310.55	$ 124.53	$ 17.33	$ 921.70
Priced tons - Intercompany (in millions)	1.33	2.30	2.30	2.30	—	8.23
Avg price per ton - Intercompany	$ 51.00	$ 51.00	$ 51.00	$ 51.00	$ —	
Contracted coal revenue - Intercompany (in millions)	$ 67.83	$ 117.30	$ 117.30	$ 117.30	$ —	$ 419.73
TOTAL CONTRACTED REVENUE (IN MILLIONS) - SEGMENT	$ 151.66	$ 502.76	$ 427.85	$ 241.83	$ 17.33	$ 1,341.43

* Actual revenue related to forward sales positions may differ materially for various reasons, including price adjustment features for coal quality and cost escalations, volume optionality provisions and potential force majeure events.

LIQUIDITY AND CAPITAL RESOURCES

I. Liquidity and Capital Resources

a. As set forth in our condensed consolidated statements of cash flows, cash provided by operations was $73.0 million and $27.0 million for the nine months ended September 30, 2025 and 2024, respectively.

b. On a net basis, bank debt did not change during the nine months ended September 30, 2025. As of September 30, 2025, our bank debt was $44.0 million.

c. We expect cash generated from operations to primarily fund our capital expenditures and our debt service. As of September 30, 2025, we also had an additional borrowing capacity of $33.8 million.

d. Total liquidity as of September 30, 2025 was $46.4 million.

II. Material Off-Balance Sheet Arrangements

a. Other than our surety bonds for reclamation, we have no material off-balance sheet arrangements. We have recorded the present value of reclamation obligations of $17.7 million, including $6.1 million at Merom, presented as asset retirement obligations ("ARO") and "accounts payable and accrued liabilities" in our accompanying condensed consolidated balance sheets. In the event we are not able to perform reclamation, we have surety bonds in place totaling $30.9 million to cover ARO.

CAPITAL EXPENDITURES ("Capex")

For the nine months ended September 30, 2025, capex was $44.3 million allocated as follows (in millions):

Oaktown – maintenance capex	$	11.5
Oaktown – investment		7.4
Merom Plant		25.4
Capex per the Condensed Consolidated Statements of Cash Flows	$	44.3

RESULTS OF OPERATIONS

Presentation of Segment Information

Our operations are divided into two primary reportable segments: Electric Operations and Coal Operations. The remainder of our operations, which are not significant enough on a stand-alone basis to warrant treatment as an operating segment, are presented as "Corporate and Other and Eliminations" within the notes to the condensed consolidated financial statements and primarily are comprised of unallocated corporate costs and activities, including a 50% interest in Sunrise Energy, LLC, a private gas exploration company with operations in Indiana and Oaktown Gas, LLC, which we account for using the equity method.

Electric Operations

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2025	2024	2025	2024
	(in thousands)		(in thousands)	
Delivered Energy	$ 77,776	$ 56,256	$ 194,044	$ 148,490
Capacity Revenue	15,459	15,860	45,110	44,506
Electric Sales	$ 93,235	$ 72,116	$ 239,154	$ 192,996
Fuel	$ (44,751)	$ (30,181)	$ (104,150)	$ (79,532)
Other Operating Costs (1)	(1)	(36)	(10)	(22)
Other Operating and Maintenance Costs (2)	(9,368)	(5,561)	(24,602)	(22,926)
Cost of Purchased Power	(2,074)	(3,149)	(11,086)	(7,694)
Utilities	(1,873)	(492)	(3,932)	(1,451)
Labor	(7,949)	(7,360)	(23,731)	(22,203)
General and Administrative	(1,308)	(1,252)	(3,972)	(3,760)
EBITDA Margin	25,911	24,085	67,671	55,408
Other Operating Revenue	192	187	3,413	518
Depreciation, Depletion and Amortization	(5,131)	(4,802)	(15,456)	(14,197)
Asset Retirement Obligations Accretion	(126)	(115)	(369)	(339)
Interest expense	(2,585)	(181)	(6,208)	(515)
Income before Income Taxes	$ 18,261	$ 19,174	$ 49,051	$ 40,875

(1) Other operating costs include costs for limestone, dibasic acid, ammonia, lime dust and soda ash.
(2) Other operating and maintenance costs include all other operating and maintenance costs with the exceptions of those costs considered variable as discussed above in (1).

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2025	2024	2025	2024
	(per MWh)		(per MWh)	
MWh Generated (in thousands)	1,530	1,074	3,706	2,670
MWh Purchased (in thousands)	48	109	264	243
MWh Sold (in thousands)	1,578	1,183	3,970	2,913
Delivered Energy	$ 49.29	$ 47.55	$ 48.88	$ 50.97
Capacity Revenue	9.80	13.41	11.36	15.28
Electric Sales	$ 59.09	$ 60.96	$ 60.24	$ 66.25
Fuel	$ (28.36)	$ (25.51)	$ (26.23)	$ (27.30)
Other Operating Costs (1)	—	(0.03)	—	(0.01)
Other Operating and Maintenance Costs (2)	(5.94)	(4.70)	(6.20)	(7.87)
Cost of Purchased Power	(1.31)	(2.66)	(2.79)	(2.64)
Utilities	(1.19)	(0.42)	(0.99)	(0.50)
Labor	(5.04)	(6.22)	(5.98)	(7.62)
General and Administrative	(0.83)	(1.06)	(1.00)	(1.29)
EBITDA Margin	16.42	20.36	17.05	19.02
Other Operating Revenue	0.12	0.16	0.86	0.18
Depreciation, Depletion and Amortization	(3.25)	(4.06)	(3.89)	(4.87)
Asset Retirement Obligations Accretion	(0.08)	(0.10)	(0.09)	(0.12)
Interest expense	(1.64)	(0.15)	(1.56)	(0.18)
Income before Income Taxes	$ 11.57	$ 16.21	$ 12.37	$ 14.03

(1) Other operating costs include costs for limestone, dibasic acid, ammonia, lime dust and soda ash.
(2) Other operating and maintenance costs include all other operating and maintenance costs with the exceptions of those costs considered variable as discussed above in (1).

Q3 2025 vs. Q3 2024

i. In Q3 2025, Total Electric Sales were $93.2 million or $59.09 per MWh sold compared to $72.1 million or $60.96 per MWh sold for Q3 2024, an increase of $21.1 million or 29.3%.

ii. In Q3 2025, Total Electric Operations expenses on a segment basis were $75.2 million or $47.64 per MWh compared to $53.1 million or $44.91 per MWh in Q3 2024, an increase of $22.1 million or 41.6%.

iii. Q3 2025 Electric Operations income before income taxes was $18.3 million or $11.57 per MWh compared to $19.2 million or $16.21 per MWh in Q3 2024, a decrease of $0.9 million or $4.64 per MWh or 28.6%.

Key drivers in Electric Operations Q3 results were:

(1) Delivered Energy revenue increased $21.5 million, or 38.3%, and $1.74 per MWh from the same period in the prior year. During 2025, (i) we sold 0.4 million more MWh of Delivered Energy, or 33.4%, (ii) we began delivery on two additional PPA contracts resulting in a $14.4 million increase, or 41.7%, (iii) MISO pricing during the quarter was in excess of 2024 prices, with July 2025 average price of $55.37 per MWh compared to $33.54 per MWh in July of 2024 and (iv) we sold 0.3 million MWh during the quarter to MISO at these elevated prices compared to 0.1 million in Q3 2024.

(2) Capacity Revenues were $15.5 million or $9.80 per MWh sold for Q3 2025 and $15.9 million or $13.41 per MWh sold for Q3 2024. Capacity revenues are not impacted by the MWh generated at the plant therefore the price per MWh sold decreased due to the allocation of revenue over increased energy volumes.

(3) Fuel costs increased $14.6 million, or 48.3%, compared to the third quarter of 2024. On a per MWh basis, fuel costs increased $2.85, or 11.2%. This change was due to increased energy production as noted above resulting in 0.2 million tons, or 37.5%, more tons of coal used. The average purchase price per ton of coal used in the plant on a segment basis, was $54.22 in the third quarter of 2025 up from $53.33 per ton in the third quarter of 2024. We also made an adjustment to coal inventory during the third quarter of 2025 as part of the Company's routine inventory reconciliation process resulting in an increase in fuel costs of $2.6 million.

(4) Other operating and maintenance costs increased $3.8 million, or 68.5%, and increased $1.24, or 26.4%, on a MWh basis. These increases were due to $3.4 million in additional planned maintenance costs compared to 2024.

(5) Electric interest expense increased $2.4 million, or 1328.2%, compared to the third quarter of 2024. On a per MWh basis, interest expense increased $1.49, or 993.3%. The increase in our interest expense relates to accretion on our prepaid delivered energy contracts that were entered into in October 2024, June 2025 and September 2025.

(6) Income before income taxes decreased $0.9 million, or 4.8%, compared to the third quarter of 2024. The main drivers of this change in income before income taxes are described in the discussion above.

YTD 2025 vs. YTD 2024

i. Total Electric Sales for YTD 2025 were $239.2 million or $60.24 per MWh compared to $193.0 million or $66.25 per MWh YTD 2024, an increase of $46.2 million or 23.9%.

ii. Total Electric Operations expenses on a segment basis YTD 2025 were $193.5 million or $48.73 per MWh compared to $152.6 million or $52.40 per MWh YTD 2024 an increase of $40.9 million or 26.8%

iii. Electric Operations income before income taxes for YTD 2025 was $49.1 million or $12.37 per MWh compared to $40.9 million or $14.03 per MWh for YTD 2024 an increase of $8.2 million or 20.0%.

Key drivers in Electric Operations YTD results were:

(1) Delivered energy increased $45.6 million, or 30.7%, compared to the first nine months of 2024. During 2025, (i) we began delivery on two additional PPA contracts resulting in a $44.3 million, or 63.4%, increase in revenue compared to 2024, (ii) we increased Delivered Energy MWh sold by 1.1 million, or 36.3%, and (iii) the average MISO price for 2025 of $41.83 per MWh is above the average 2024 price of $30.91, or an increase of 35.3%.

(2) Fuel increased $24.6 million, or 31.0%, compared to the first nine months of 2024. The increase in fuel costs were directly related to the increase in MWh generated, requiring the increased use of fuel by 0.4 million tons of coal, or 30.1%. On a per MWh basis, fuel decreased $1.07, or 3.9%, at an average cost of $53.88 per ton for 2025 compared to an average cost of $54.83 per ton for 2024. We also made an adjustment to coal inventory during the third quarter of 2025 as a part of the Company's routine inventory reconciliation process resulting in an increase in fuel costs of $2.6 million.

(3) The cost of purchased power increased $3.4 million, or 44.1%, compared to year-to-date 2024. When energy hours at the Merom Hub are priced below our production cost or during outages at Merom, we have the option to make net hourly purchases of power in the MISO market, which we record as cost of purchased power.

(4) Utilities increased $2.5 million, or 171.0%, compared to the first nine months of 2024. This change was due to increased production at the Merom Plant described above as well as a change in meters for auxiliary power.

(5) Other operating revenue increased $2.9 million, or 558.9%, compared to the first nine months of 2024. On a per MWh basis, other operating revenues increased $0.68, or 377.8%. These changes were due to revenue received related to contractual negotiations on the former exclusivity agreement.

(6) Electric interest expense increased $5.7 million, or 1105.4%, compared to the first nine months of 2024. On a per MWh basis, interest expense increased $1.38, or 766.7%. The increase in our interest expense relates to accretion on our prepaid delivered energy contracts that were entered into in October 2024, June 2025 and September 2025.

(7) Income before income taxes increased $8.2 million, or 20.0%, compared to the first nine months of 2024. The main drivers of this change in income before income taxes are described in the discussion above.

Coal Operations

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2025	2024	2025	2024
	(in thousands)		(in thousands)	
Coal Sales	$ 68,814	$ 48,320	$ 169,117	$ 160,066
Fuel	$ (574)	$ (572)	$ (1,564)	$ (2,557)
Other Operating and Maintenance Costs	(35,046)	(27,031)	(77,147)	(80,419)
Utilities	(2,670)	(3,094)	(9,270)	(10,639)
Labor	(19,625)	(19,361)	(57,671)	(66,241)
General and Administrative	(2,062)	(2,082)	(6,290)	(8,012)
EBITDA Margin	8,837	(3,820)	17,175	(7,802)
Other Operating Revenue	1,647	721	4,370	2,028
Depreciation, Depletion and Amortization	(3,992)	(9,013)	(14,148)	(28,671)
Asset Retirement Obligations Accretion	(320)	(295)	(941)	(869)
Exploration Costs	(38)	(62)	(157)	(179)
Gain on disposal or abandonment of assets, net	2,334	290	2,410	536
Interest expense	(2,342)	(2,511)	(6,261)	(8,908)
Income (Loss) before Income Taxes	$ 6,126	$ (14,690)	$ 2,448	$ (43,865)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2025	2024	2025	2024
	(per ton)		(in thousands)	
Tons Sold	1,355	926	3,316	2,989
Coal Sales	$ 50.79	$ 52.18	$ 51.00	$ 53.55
Fuel	$ (0.42)	$ (0.62)	$ (0.47)	$ (0.86)
Other Operating and Maintenance Costs	(25.86)	(29.19)	(23.27)	(26.90)
Utilities	(1.97)	(3.34)	(2.80)	(3.56)
Labor	(14.48)	(20.91)	(17.39)	(22.16)
General and Administrative	(1.52)	(2.25)	(1.90)	(2.68)
EBITDA Margin	6.54	(4.13)	5.17	(2.61)
Other Operating Revenue	1.22	0.78	1.32	0.68
Depreciation, Depletion and Amortization	(2.95)	(9.73)	(4.27)	(9.59)
Asset Retirement Obligations Accretion	(0.24)	(0.32)	(0.28)	(0.29)
Exploration Costs	(0.03)	(0.07)	(0.05)	(0.06)
Gain on disposal or abandonment of assets, net	1.72	0.31	0.73	0.18
Interest expense	(1.73)	(2.71)	(1.89)	(2.98)
Income (Loss) before Income Taxes	$ 4.53	$ (15.87)	$ 0.73	$ (14.67)

Q3 2025 vs. Q3 2024

i. In Q3 2025, Total Coal Sales on a segment basis were $68.8 million, or $50.79 per ton sold compared to $48.3 million or $52.18 per ton from Q3 2024, an increase of $20.5 million or 42.4%.

ii. In Q3 2025, Total Coal Operations Expenses on a segment basis were $66.7 million, or $49.20 per ton sold, compared to $64.0 million or $69.14 per ton from Q3 2024, an increase of $2.7 million or 4.2%.

iii. Q3 2025 Coal Operations Net Income on a segment basis was $6.1 million compared to a net loss of $14.7 million in Q3 2024, an increase of $20.8 million or 141.7%.

Key drivers in Q3 2025 Coal Operations results were:

(1) Coal sales increased $20.5 million, or 42.4%, compared to the third quarter of 2024. On a per ton basis, coal sales decreased $1.39, or 2.7%. These changes were primarily due to increased third-party contractual coal sales of 0.4 million tons during the period, partially offset by a decrease in coal prices per ton of $1.39.

(2) Other operating and maintenance costs increased $8.0 million, or 29.7%, compared to the third quarter of 2024. On a per ton basis other operating and maintenance costs decreased $3.33, or 11.4%. These changes were the result of a $2.6 million increase in sales related royalties, an increase of $8.4 million related to coal cost of sales, $1.0 million decrease in group health insurance costs and a $1.0 million decrease in maintenance costs.

(3) Depreciation, depletion and amortization decreased $5.0 million, or 55.7%, compared to the third quarter of 2024. On a per ton basis, depreciation, depletion and amortization decreased $6.78, or 69.7%. This change was the result of the non-cash impairment charge recognized in Q4 2024 in the amount $215.1 million.

(4) Gain on disposal or abandonment of assets, net, increased $2.0 million, or 704.8%, and $1.41, or 454.8%, on a per ton basis compared to the third quarter of 2024. This change was due to the sale of land during the third quarter of 2025.

(5) Income before income taxes increased $20.8 million, or 141.7%, compared to the third quarter of 2024. The main drivers of this change in income before income taxes are described in the discussion above.

YTD 2025 vs. YTD 2024

i. Total Coal Sales on a segment basis YTD 2025 were $169.1 million or $51.00 per ton compared to $160.1 million or $53.55 per ton YTD 2024, an increase of $9.1 million or 5.7%.

ii. Total Coal Operations expenses YTD 2025 were $173.4 million or $52.31 per ton $206.5 million or $69.08 per ton for YTD 2024, a decrease of $33.1 million or 16.0%.

iii. Income before income taxes YTD 2025 was $2.4 million or $.74 per ton compared to a loss of $43.9 million or $14.68 per ton YTD 2024, an increase of $46.3 million or 105.6%.

Key drivers in YTD 2025 Coal Operations results were:

(1) Labor decreased $8.6 million, or 12.9%, compared to the first nine months of 2024. On a per ton basis, labor decreased $4.77, or 21.5%. This change was the result of the organizational restructuring that occurred in February 2024 which reduced the Coal Operations headcount to 626 as of September 30, 2025 from 924 prior to the restructuring.

(2) Other operating revenue increased $2.3 million, or 115.5%, compared to the first nine months of 2024. On a per ton basis, other operating revenue increased $0.64, or 94.1%. This change was the result of increased utilization of our rail facility by a customer resulting in an increase in transloading fee revenue.

(3) Depreciation, depletion and amortization costs decreased $14.5 million, or 50.7%, compared to the first nine months of 2024. On a per ton basis, depreciation, depletion and amortization decreased $5.32, or 55.5%. This change was the result of the non-cash impairment charge recognized in Q4 2024 in the amount $215.1 million.

(4) Interest expense decreased $2.6 million, or 29.7%, compared to the first nine months of 2024. Interest expense on a per ton basis decreased $1.09, or 36.6%. Our decreased interest expense primarily relates to reductions of convertible debt of $11.0 million and related party debt of $5.0 million.

(5) Income before income taxes increased $46.3 million, or 105.6%, compared to the first nine months of 2024. The main drivers of this change in loss before income taxes are described in the discussion above.

Quarterly coal sales and cost data on a segment basis are as follows (in thousands, except per ton data and wash plant recovery percentage):

All Mines	4th 2024	1st 2025	2nd 2025	3rd 2025	T4Qs
Tons produced	971	1,020	1,059	1,034	4,084
Tons sold	875	1,071	890	1,355	4,191
Wash plant recovery in %	62 %	64 %	66 %	64 %	
Capex (Coal Operations)	$ 11,079	$ 6,244	$ 5,793	$ 6,873	$ 29,989
Maintenance capex (Coal Operations)	$ 4,492	$ 4,000	$ 3,691	$ 3,846	$ 16,029
Maintenance capex per ton sold (Coal Operations)	$ 5.13	$ 3.73	$ 4.15	$ 2.84	$ 3.82
Average cost per ton sold[i]	$ 43.25	$ 43.65	$ 46.03	$ 42.74	

All Mines	4th 2023	1st 2024	2nd 2024	3rd 2024	T4Qs
Tons produced	1,331	1,271	889	873	4,364
Tons sold	1,461	1,214	849	926	4,450
Wash plant recovery in %	62 %	60 %	59 %	60 %	
Capex (Coal Operations)	$ 17,867	$ 8,632	$ 7,560	$ 6,810	$ 40,869
Maintenance capex (Coal Operations)	$ 13,567	$ 8,085	$ 6,014	$ 4,208	$ 31,874
Maintenance capex per ton (Coal Operations)	$ 9.29	$ 6.66	$ 7.08	$ 4.54	$ 7.16
Average cost per ton sold[i]	$ 53.78	$ 51.65	$ 49.94	$ 52.22	

(i) Average cost per ton sold is calculated as the sum of the Coal Operation's "Fuel", "Other Operating and Maintenance Costs", "Utilities" and "Labor" costs. Coal Operations costs are presented in the "Presentation of Segment Information" above.

Presentation of Consolidated Information

EARNINGS (LOSS) PER SHARE

	4th 2024	1st 2025	2nd 2025	3rd 2025
Basic	$ (5.06)	$ 0.23	$ 0.19	$ 0.56
Diluted	$ (5.06)	$ 0.23	$ 0.19	$ 0.55

	4th 2023	1st 2024	2nd 2024	3rd 2024
Basic	$ (0.31)	$ (0.05)	$ (0.27)	$ 0.04
Diluted	$ (0.31)	$ (0.05)	$ (0.27)	$ 0.04

INCOME TAXES

Our effective tax rate (ETR) is estimated at ~0% and ~24% for the nine months ended September 30, 2025 and 2024, respectively. For the nine months ended September 30, 2025, we estimated our annual ETR based upon projected annual income (loss), forecasted permanent tax differences, discrete items, and statutory rates in states in which we operate. Our ETR differs from the statutory rate due primarily to statutory depletion in excess of tax basis and changes in the valuation allowance. The deduction for statutory percentage depletion does not necessarily change proportionately to changes in income (loss) before income taxes.

RESTRICTED STOCK GRANTS

See *"Item 1. Financial Statements - Note 9 - Stock Compensation Plans"* for a discussion of RSUs.

CRITICAL ACCOUNTING ESTIMATES

We believe that the estimates of coal reserves, asset retirement obligation liabilities, deferred tax accounts, valuation of inventory, and the estimates used in impairment analysis are our critical accounting estimates.

The reserve estimates are used in the depreciation, depletion, and amortization calculations and our internal cash flow projections. If these estimates turn out to be materially under or over-stated, our depreciation, depletion and amortization expense and impairment test may be affected. The process of estimating reserves is complex, requiring significant judgment in the evaluation of all available geological, geophysical, engineering and economic data. The reserve estimates are prepared by professional engineers, both internal and external, and are subject to change over time as more data becomes available. Changes in the reserves estimates from the prior year were nominal.

SMCRA and similar state statutes require, among other things, that surface disturbance be restored in accordance with specified standards and approved reclamation plans. SMCRA requires us to restore affected surface areas to approximate the original contours as contemporaneously as practicable with the completion of surface mining operations. Federal law and some states impose on mine operators the responsibility for replacing certain water supplies damaged by mining operations and repairing or compensating for damage to certain structures occurring on the surface as a result of mine subsidence, a consequence of longwall mining and possibly other mining operations.

Obligations are reflected at the present value of their future cash flows. We reflect accretion of the obligations for the period from the date they are incurred through the date they are extinguished. The ARO assets are amortized using the units-of-production method over estimated recoverable (proven and probable) reserves. We use credit-adjusted risk-free discount rates ranging from 7% to 10% to discount the obligation, inflation rates anticipated during the time to reclamation, and cost estimates prepared by its engineers inclusive of market risk premiums. Activities include reclamation of pit and support acreage at surface mines, sealing portals at underground mines, and reclamation of refuse areas and slurry ponds.

Accretion expense is recognized on the obligation through the expected settlement date. On at least an annual basis, we review our entire reclamation liability and make necessary adjustments for permit changes as granted by state authorities, changes in the timing and extent of reclamation activities, and revisions to cost estimates and productivity assumptions, to reflect current experience. Any difference between the recorded amount of the liability and the actual cost of reclamation will be recognized as a gain or loss when the obligation is settled.

We have analyzed our filing positions in all of the federal and state jurisdictions where we are required to file income tax returns, as well as all open tax years in these jurisdictions. We identified our federal tax return and our Indiana state tax return as “major” tax jurisdictions. We believe that our income tax filing positions and deductions would be sustained on audit and do not anticipate any adjustments that will result in a material change to our consolidated financial position. We have not taken any significant uncertain tax positions, and our tax provisions and returns are prepared by a large public accounting firm with significant experience in energy related industries. Changes to the estimates from reported amounts in the prior year were not significant.

Inventory is valued at a lower of cost or NRV. Anticipated utilization of low sulfur, higher-cost coal from our Freelandville, and Prosperity mines has the potential to create NRV adjustments as our estimated needs change. The NRV adjustments are subject to change as our costs may fluctuate due to higher or lower production and our NRV may fluctuate based on sales contracts we enter into from time to time. As of September 30, 2025, and December 31, 2024, coal inventory includes NRV adjustments of $0.1 million and $0.3 million, respectively.

Long-lived assets used in operations are depreciated and assessed for impairment annually or whenever changes in facts and circumstances indicate a possible significant deterioration in future cash flows is expected to be generated by an asset group. For impairment assessments, management groups individual assets based on a judgmental assessment of the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. The determination of the lowest level of cash flows is largely based on nature of production, common infrastructure, common sales points, common regulation and management oversight to make such determinations. These determinations could impact the determination and measurement of a potential asset impairment. Management evaluates

assets for impairment through an established process in which changes to significant assumptions such as prices, volumes and future development plans are reviewed. If, upon review, the sum of the undiscounted pre-tax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates believed to be consistent with those used by principal market participants. The expected future cash flows used for impairment reviews and related fair value calculations are typically based on judgmental assessments of future volumes, commodity prices, operating costs and capital investment plans, considering all available information at the date of review. Changes to any of the market-based assumptions can significantly affect estimates of undiscounted and discounted pre-tax cash flows and impact the recognition and amount of impairments.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

No material changes from the disclosure in our 2024 Annual Report on Form 10-K.

ITEM 4. CONTROLS AND PROCEDURES

DISCLOSURE CONTROLS

We maintain a system of disclosure controls and procedures that are designed for the purpose of ensuring that information required to be disclosed in our SEC reports is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms and that such information is accumulated and communicated to our CEO and CFO and as appropriate to allow timely decisions regarding required disclosure.

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our CEO and CFO of the effectiveness of the design and operation of our disclosure controls and procedures. Based on that evaluation, our CEO and CFO concluded that our disclosure controls and procedures are effective.

There have been no changes to our internal control over financial reporting during the quarter ended September 30, 2025, that materially affected or are reasonably likely to materially affect our internal control over financial reporting.

FORWARD-LOOKING STATEMENTS

Certain statements and information in this Quarterly Report on Form 10-Q may 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," "estimate," "expect," "forecast," "may," "project," "will," 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 statements reflect our current views with respect to future events and are subject to numerous assumptions that we believe are open to a wide range of uncertainties and business risks, and actual results may 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:

- changes in macroeconomic and market conditions and market volatility, and the impact of such changes and volatility on our financial position;
- fluctuations in weather, gas and electricity commodity costs, inflation and economic conditions impact demand of our customers and our operating results;
- the outcome or escalation of current hostilities in Ukraine and Israel;
- changes in competition in electricity or coal markets and our ability to respond to such changes;
- changes in coal prices, demand, and availability which could affect our operating results and cash flows;
- risks associated with the expansion of our operations and properties;

- legislation, regulations, administrative actions (e.g., Executive Orders), and court decisions and interpretations thereof, including those relating to the environment and the release of greenhouse gases, mining, miner health and safety, and health care, as well as those relating to data privacy protection;
- deregulation of the electric utility industry or the effects of any adverse change in the coal industry, electric utility industry, or general economic conditions;
- dependence on significant or long-term customer contracts, including renewing customer contracts upon expiration of existing contracts;
- changing global economic conditions or the geopolitical environment in industries in which our customers operate;
- anticipated changes in the U.S. political environment, including those resulting from the change in Presidential Administration and control of Congress, and to regulatory agencies;
- changes in attitude toward environmental, social, and governance ("ESG") matters among regulators, investors and parties with which we do business;
- the effect of changes in taxes or tariffs and other trade measures; the U.S. has implemented higher tariffs on imports into the U.S. which could impact the Company's procurement and sourcing strategies;
- risks relating to inflation and increasing interest rates;
- liquidity constraints, including due to restrictions contained in our indebtedness and those resulting from any future unavailability of financing;
- customer bankruptcies, a decline in customer creditworthiness, or customer cancellations or breaches to existing contracts, or other failures to perform;
- customer delays, failure to take coal under contracts or defaults in making payments;
- adjustments made in price, volume or terms to existing coal supply and customer agreements;
- our productivity levels and margins earned on our coal or electricity sales;
- supply chain disruptions and changes in equipment, raw material, service or labor costs or availability, including due to inflationary pressures;
- changes in the availability of skilled labor;
- our ability to maintain satisfactory relations with our employees;
- increases in labor costs, 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-related or other factors;
- risks associated with major mine-related or other accidents, mine fires, mine floods or other interruptions, including unanticipated operating conditions and other events that are not within our control;
- results of litigation, including claims not yet asserted;
- difficulty maintaining our surety bonds for mine reclamation;
- decline in or change in the coal industry's share of electricity generation, including as a result of environmental concerns related to coal mining and combustion and the cost and perceived benefits of other sources of electricity, such as natural gas, nuclear energy, and renewable fuels;
- risks resulting from climate change or natural disasters;
- difficulty in making accurate assumptions and projections regarding post-mine reclamation;
- uncertainties in estimating and replacing our coal reserves;
- the impact of current and potential changes to federal or state tax rules and regulations, including the effects of the OBBBA or a loss or reduction of benefits from certain tax deductions and credits;
- difficulty obtaining commercial property insurance;
- 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;
- any future pandemics and their impacts, both in their intrinsic severity and in the political and social responses to them, which could affect, among other things, our operations and personnel, the demand for coal, the financial condition of our customers and suppliers and available liquidity and capital; and

- other factors, including those discussed in *"Item 1A. Risk Factors"* in our Annual Report on Form 10-K.

If one or more of these or other risks or uncertainties materialize, or should underlying assumptions prove incorrect, our actual results may differ materially from those described in any forward-looking statement. When considering forward-looking statements, you should also keep in mind the risk factors described in "*Item 1A. Risk Factors*" in our Annual Report on Form 10-K. The risk factors could also cause our actual results to differ materially from those contained in any forward-looking statement. We disclaim any obligation to update the above list 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 Quarterly Report on Form 10-Q; other reports filed by us with the U.S. Securities and Exchange Commission ("SEC"); our press releases; our website ***www.halladorenergy.com*** and written or oral statements made by us or any of our officers or other authorized persons acting on our behalf.

PART II - OTHER INFORMATION

ITEM 1A. RISK FACTORS

Except as set forth below, there have been no material changes to the Risk Factors disclosed in Part I, Item 1A, *Risk Factors*, of the Company's 2024 Form 10-K.

Our Electric and Coal 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.

In October 2025, the Company submitted an application for a National Pollutant Discharge Elimination System ("NPDES") permit under the proposed U.S. Environmental Protection Agency's ("EPA") Steam Electric Power Generating Effluent Guidelines ("ELG") Deadline Extensions Rule, published October 2, 2025. The proposed rule extends multiple compliance deadlines originally established by the 2024 ELG rule including deadlines for zero-discharge systems (e.g., flue gas desulfurization wastewater, bottom ash transport water, and combustion residual leachate) by five to six years (e.g., from December 31, 2029 to December 31, 2034) and includes new provisions for alternative applicability dates, transferability between compliance options and authorize alternative applicability dates based on site-specific considerations.

The Company's permit application was approved November 7, 2025 and is consistent with the extended deadlines and flexibility provided by the proposed Deadline Extensions Rule. The rule is currently in the public comment stage, with comments due November 3, 2025, and has not yet been finalized.

If the finalized ruling does not include the extension of the compliance deadlines the Company would be unable to discharge under the current ELG rule and thus would be out of compliance with the Clean Water Act as of December 31, 2025**,** potentially subjecting it to enforcement actions, penalties, or required to implement alternative discharge controls immediately.

ITEM 4. MINE SAFETY DISCLOSURES

See Exhibit 95.1 to this Form 10-Q for a listing of our mine safety violations.

ITEM 6. EXHIBITS

Exhibit No.	Document
31.1	SOX 302 Certification - Chief Executive Officer
31.2	SOX 302 Certification - Chief Financial Officer
32	SOX 906 Certification
95.1	Mine Safety Disclosures
101.INS	Inline XBRL Instance Document
101.SCH	Inline XBRL Schema Document
101.CAL	Inline XBRL Calculation Linkbase Document
101.LAB	Inline XBRL Labels Linkbase Document
101.PRE	Inline XBRL Presentation Linkbase Document
101.DEF	Inline XBRL Definition Linkbase Document
104	Cover Page Interactive Data File (embedded with the Inline XBRL document)

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.

HALLADOR ENERGY COMPANY

Date: November 10, 2025

/s/ TODD E. TELESZ

Todd E. Telesz, CFO (Principal Financial Officer and Principal Accounting Officer)