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, 2026

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 5, 2026, we had 47,145,251 shares of common stock outstanding.

TABLE OF CONTENTS

PART I - FINANCIAL INFORMATION	1
ITEM 1. FINANCIAL STATEMENTS (Unaudited)	1
Condensed Consolidated Balance Sheets	1
Condensed Consolidated Statements of Operations	2
Condensed Consolidated Statements of Cash Flows	3
Condensed Consolidated Statements of Stockholders' Equity	4
Notes to Condensed Consolidated Financial Statements	5
ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS	22
ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK	40
ITEM 4. CONTROLS AND PROCEDURES	41
PART II - OTHER INFORMATION	42
ITEM 1. LEGAL PROCEEDINGS	42
ITEM 1A. RISK FACTORS	42
ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS	44
ITEM 3. DEFAULTS UPON SENIOR SECURITIES	44
ITEM 4. MINE SAFETY DISCLOSURES	44
ITEM 5. OTHER INFORMATION	44
ITEM 6. EXHIBITS	45
SIGNATURES	46

PART I - FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS

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

	September 30, 2026	December 31, 2025
ASSETS		
Current assets:		
Cash and cash equivalents	$ 103,155	$ 10,070
Restricted cash	329,840	5,302
Accounts receivable	23,169	13,989
Inventory	42,561	42,534
Parts and supplies	52,392	45,854
Prepaid expenses	2,149	5,638
Total current assets	553,266	123,387
Property, plant and equipment:		
Land and mineral rights	69,952	69,952
Buildings and equipment	445,171	421,037
Mine development	102,302	102,302
Construction work in progress	92,009	39,671
Finance lease right-of-use assets	10,987	12,591
Total property, plant and equipment	720,421	645,553
Less - accumulated depreciation, depletion and amortization	(374,584)	(367,775)
Total property, plant and equipment, net	345,837	277,778
Equity method investments	2,642	2,647
Operating lease right-of-use assets	2,525	—
Other noncurrent assets	4,471	4,241
Total assets	$ 908,741	$ 408,053
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 18,449	$ 12,594
Accrued liabilities and other	39,166	29,254
Current portion of lease financing	2,177	7,411
Contract liabilities - current	103,730	103,343
Total current liabilities	163,522	152,602
Long-term liabilities:		
Debt, net	525,965	29,678
Deferred income taxes	1,991	1,833
Asset retirement obligations	16,492	15,241
Contract liabilities - long-term	10,000	45,714
Other	3,759	3,152
Total long-term liabilities	558,207	95,618
Total liabilities	721,729	248,220
Commitments and contingencies (Note 15)		
Stockholders' equity:		
Preferred stock, $.10 par value, 10,000 shares authorized; none issued	—	—
Common stock, $.01 par value, 100,000 shares authorized; 47,147 and 43,817 issued and outstanding, as of September 30, 2026 and December 31, 2025, respectively	471	438
Additional paid-in capital	259,162	202,963
Retained deficit	(72,621)	(43,568)
Total stockholders' equity	187,012	159,833
Total liabilities and stockholders' equity	$ 908,741	$ 408,053

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,	
	2026	2025	2026	2025
SALES AND OPERATING REVENUES:				
Electric sales	$ 92,846	$ 93,235	$ 220,132	$ 239,154
Coal sales	36,128	51,256	111,809	119,588
Other revenues	1,276	2,066	4,302	8,364
Total sales and operating revenues	130,250	146,557	336,243	367,106
EXPENSES:				
Fuel	28,764	27,119	59,178	57,392
Other operating and maintenance costs	31,547	44,415	99,835	101,759
Cost of purchased power	11,103	2,074	34,599	11,086
Utilities	5,108	4,543	15,082	13,202
Labor	30,488	27,574	86,688	81,402
Depreciation, depletion and amortization	7,623	9,142	28,134	29,661
Asset retirement obligations accretion	427	446	1,251	1,310
Exploration costs	36	38	407	157
General and administrative	6,971	4,770	21,381	19,096
(Gain) loss on disposal or abandonment of assets, net	343	(2,334)	157	(2,410)
Total operating expenses	122,410	117,787	346,712	312,655
INCOME (LOSS) FROM OPERATIONS	7,840	28,770	(10,469)	54,451
Interest income	855	289	1,281	416
Interest expense (1)	(6,007)	(4,927)	(13,753)	(12,469)
Loss on extinguishment of debt	(5,717)	—	(5,947)	—
Equity method investment (loss)	358	(248)	(7)	(287)
NET INCOME (LOSS) BEFORE INCOME TAXES	(2,671)	23,884	(28,895)	42,111
INCOME TAX EXPENSE (BENEFIT):				
Current	—	—	—	—
Deferred	1,826	—	158	—
Total income tax expense (benefit)	1,826	—	158	—
NET INCOME (LOSS)	$ (4,497)	$ 23,884	$ (29,053)	$ 42,111
NET INCOME (LOSS) PER SHARE:				
Basic	$ (0.10)	$ 0.56	$ (0.62)	$ 0.98
Diluted	$ (0.10)	$ 0.55	$ (0.62)	$ 0.97
WEIGHTED AVERAGE SHARES OUTSTANDING				
Basic	47,145	43,007	46,937	42,869
Diluted	47,145	43,434	46,937	43,287
(1) Interest Expense:				
Interest on debt	$ 3,408	$ 1,763	$ 5,249	$ 4,661
Other interest	1,923	2,585	7,027	6,208
Amortization of debt issuance costs	676	579	1,478	1,600
Total interest expense	$ 6,007	$ 4,927	$ 13,753	$ 12,469

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,	
	2026	2025
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ (29,053)	$ 42,111
Adjustments to reconcile net income (loss) to net cash (used in) provided by operating activities:		
Deferred income tax	158	—
Equity method investment loss	7	287
Depreciation, depletion and amortization	28,134	29,661
Loss (gain) on disposal or abandonment of assets, net	157	(2,410)
Loss on extinguishment of debt	5,947	—
Amortization of debt issuance costs	1,478	1,600
Asset retirement obligations accretion	1,251	1,310
Paid-in-kind interest	1,924	—
Cash paid on asset retirement obligation reclamation	(452)	(455)
Stock-based compensation	3,730	2,144
Amortization of contract liabilities	(86,806)	(82,639)
Accretion on contract liabilities	7,027	5,659
Amortization of right-of-use assets	527	—
Other	934	274
Change in current assets and liabilities:		
Accounts receivable	(9,180)	(9,325)
Inventory	(27)	8,679
Parts and supplies	(6,538)	(4,898)
Prepaid expenses	(1,618)	1,190
Accounts payable and accrued liabilities	12,803	1,923
Contract liabilities	44,453	77,867
Net cash (used in) provided by operating activities	(25,144)	72,978
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(91,080)	(44,277)
Proceeds from sale of equipment	200	2,891
Investment in equity method investments	—	(394)
Net cash used in investing activities	(90,880)	(41,780)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Payments on debt	(79,200)	(63,000)
Borrowings of debt	599,200	63,000
Payments on lease financing	(6,474)	(5,187)
Debt issuance costs	(32,381)	(330)
Proceeds from ATM offering, net of issuance costs	189	—
Proceeds from public offering, net of issuance costs	53,764	—
Taxes paid on vesting of RSUs	(1,451)	(2,352)
Net cash (used in) provided by financing activities	533,647	(7,869)
Increase in cash, cash equivalents, and restricted cash	417,623	23,329
Cash, cash equivalents, and restricted cash, beginning of period	15,372	12,153
Cash, cash equivalents, and restricted cash, end of period	$ 432,995	$ 35,482
CASH, CASH EQUIVALENTS, AND RESTRICTED CASH:		
Cash and cash equivalents	$ 103,155	$ 12,663
Restricted cash	329,840	22,819
	$ 432,995	$ 35,482
SUPPLEMENTAL CASH FLOW INFORMATION:		
Cash paid for interest	$ 3,296	$ 4,718
SUPPLEMENTAL NON-CASH FLOW INFORMATION:		
Non-cash change in capital expenditures included in accounts payable and prepaid expense	$ 6,116	$ (5,855)
Repayment of TCB Credit Facility directly by lenders from KLIM proceeds	$ 100,200	$ —
PIK interest	$ 1,924	$ —
Right-of-use asset additions	$ 2,407	$ —

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 Capital	Retained Deficit	Total Stockholders' Equity
	Shares	Amount			
Balance, June 30, 2026	47,144	$ 471	$ 257,985	$ (68,124)	$ 190,332
Stock-based compensation	—	—	1,187	—	1,187
Stock issued on vesting of RSUs	3	—	(10)	—	(10)
Net Loss	—	—	—	(4,497)	(4,497)
Balance, September 30, 2026	47,147	$ 471	$ 259,162	$ (72,621)	$ 187,012
Balance, December 31, 2025	43,817	$ 438	$ 202,963	$ (43,568)	$ 159,833
Stock-based compensation	—	—	3,730	—	3,730
Stock issued on vesting of RSUs	213	2	(1,453)	—	(1,451)
Taxes paid on vesting of RSUs	(88)	(1)	1	—	—
Stock issued in ATM offering, net of issuance costs	11	—	189	—	189
Stock issued in public offering	3,194	32	53,732	—	53,764
Net loss	—	—	—	(29,053)	(29,053)
Balance, September 30, 2026	47,147	$ 471	$ 259,162	$ (72,621)	$ 187,012

	Common Stock Issued		Additional Paid-in Capital	Retained Deficit	Total Stockholders' Equity
	Shares	Amount			
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

See accompanying notes to the condensed consolidated financial statements.

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

(1) BASIS OF PRESENTATION

Organization

Hallador Energy Company ("Hallador" or the "Company") is a vertically-integrated, independent power producer ("IPP") and fuel company with operations primarily in Indiana. The Company operates across multiple stages of the energy supply chain, from accredited capacity and electricity to coal. The Company's condensed consolidated financial statements have been prepared in accordance with U.S. generally accepted accounting principles ("GAAP"). The condensed consolidated financial statements include the accounts of Hallador and our wholly owned subsidiaries, including our main operating subsidiaries, Hallador Power Company, LLC ("Hallador Power") and Sunrise Coal, LLC ("Sunrise") and their respective subsidiaries, as well Turtle Creek Gas Holdings, LLC and its subsidiary Turtle Creek Gas Generation, LLC and Hourglass Sands, LLC. Additionally, we hold 50% interests in Sunrise Energy, LLC ("Sunrise Energy"), a private gas exploration company with operations in Indiana and Oaktown Gas, LLC ("Oaktown Gas"), which we account for using the equity method. Hallador Power provides accredited capacity and energy to utilities and other energy market participants through the Midcontinent Independent System Operator ("MISO") interconnection, and Sunrise mines bituminous coal in Indiana to serve various power plants in the Midwest and Southeast United States.

Reclassifications

During the second quarter of 2026, it was determined that electric sales and utilities expenses were each understated by $2.7 million in the unaudited condensed consolidated statements of operations for the three months ended March 31, 2026. The understatements had no impact on net loss for the period. These amounts have been properly reflected in our unaudited condensed consolidated statement of operations for the nine months ended September 30, 2026 and have no impact on our unaudited condensed consolidated statement of operations the three months ended September 30, 2026. As the impacts are not considered material to the previously reported amounts, they will be corrected when we present the three months ended March 31, 2026 in our March 31, 2027 Quarterly Report on Form 10-Q. This correction did not impact previously reported amounts of assets, liabilities, equity, net loss, or cash flows.

Certain other 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.

Basis of Presentation

Our unaudited condensed consolidated financial statements have been prepared in accordance with GAAP and with the instructions to Form 10-Q and Article 10 of Regulation S-X for interim financial information. Accordingly, these financial statements do not include all of the information required by GAAP or Securities and Exchange Commission ("SEC") rules and regulations for complete financial statements. In the opinion of management, these financial statements reflect all adjustments (consisting of normal recurring adjustments) necessary for a fair presentation of the results of operations for the interim periods presented. The results of operations for any interim period are not necessarily indicative of results for the full year. These unaudited condensed consolidated financial statements should be read in conjunction with our 2025 consolidated financial statements and notes thereto included in our 2025 Annual Report on Form 10-K (our "2025 10-K"). All significant intercompany accounts and transactions have been eliminated.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Estimates and assumptions are used in accounting for, among other things, deferred income tax accounts, coal reserves, depreciation, depletion, and amortization, impairment analyses, and calculation of asset retirement obligations ("ARO"). Actual results could differ from those estimates.

Change in Accounting Estimate

On May 1, 2026, the Company entered into a 12-year capacity agreement with a subsidiary of a utility for planning years 2028 through 2040, as previously reported on the Company's Current Report on Form 8-K filed May 6, 2026. As a result of this agreement, together with the Company's other long-term contracted commitments and future maintenance plans, the Company reevaluated the estimated remaining useful life of the Merom Generating Station, (the "Merom Station"), and determined that the plant's estimated operating life should also be extended through 2040, compared to the previous estimate of 2032. Accordingly, effective June 1, 2026, the Company extended the estimated useful lives of the plant and related assets to align with the revised remaining life of the facility. This change was accounted for prospectively as a change in accounting estimate; depreciation expense recorded in prior periods was not adjusted, and the remaining net book value of the affected assets is being depreciated over the revised remaining useful lives. The effect of this change for the three and nine months ended September 30, 2026 was a decrease in depreciation expense of $3.6 million and $4.8 million, respectively or approximately $0.08 and $0.10 per basic and diluted share, respectively, which impacted our Electric Operations segment.

(2) RECENT ACCOUNTING PRONOUNCEMENTS

Recent Accounting Pronouncements – Not Yet Adopted

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 ("ASU 2024-03"). The update is intended to improve 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) RESTRICTED CASH

The following table reconciles cash, cash equivalents, and restricted cash reported in the condensed consolidated balance sheets to the total shown in the condensed consolidated statements of cash flows (in thousands):

	September 30, 2026	December 31, 2025
Cash and cash equivalents	$ 103,155	$ 10,070
Restricted cash - construction account	293,952	—
Restricted cash - letter of credit collateral	19,731	—
Restricted cash - other	16,157	5,302
Total cash and cash equivalents and restricted cash	$ 432,995	$ 15,372

Restricted cash is classified as current in the condensed consolidated balance sheets based on the nature of the restriction and the expected timing of its release or use.

(4) INVENTORY

Inventory is valued at the lower of cost or net realizable value ("NRV"). Coal inventory includes NRV adjustments of $0.5 million and $0.1 million as of September 30, 2026, and December 31, 2025, respectively. During the three months ended September 30, 2025, as part of the Company's routine inventory reconciliation process, a downward adjustment of $2.6 million was recorded to coal inventory.

(5) DEBT

KLIM Facility

On September 15, 2026 (the "KLIM Closing Date"), the Company and its wholly owned subsidiary, Turtle Creek Gas Holdings, LLC ("Turtle Creek"), each as a co-borrower, jointly and severally liable for all obligations thereunder (and

together, the "KLIM Borrowers"), entered into a Credit Agreement (the "KLIM Credit Agreement") with U.S. Bank Trust Company, National Association, as administrative agent, U.S. Bank National Association, as collateral agent, Kennedy Lewis Investment Management LLC ("KLIM"), acting for certain managed or advised funds and accounts, and the other lenders from time to time party thereto. The KLIM Credit Agreement provides for a senior secured term loan facility (the "KLIM Facility") to finance the development and construction of a 460 MW natural gas-fired peaking generation facility in Sullivan County, Indiana (the "Turtle Creek Project") to be owned and operated by Turtle Creek Gas Generation, LLC ("Turtle Creek Gas"), a wholly owned subsidiary of Turtle Creek.

The KLIM Facility provides for term loans in an aggregate principal amount of up to $600.0 million, consisting of a $550.0 million initial term loan, which was funded in September 2026, and a $50.0 million delayed draw term loan commitment, which is available until September 15, 2027, subject to an agreed draw schedule and funding conditions. The delayed draw term loan may only be used to fund the Turtle Creek Project. As of September 30, 2026, no amounts had been drawn under the delayed draw term loan commitment. Amounts repaid or prepaid under the KLIM Facility may not be re-borrowed. The KLIM Facility matures on September 15, 2029, and may be extended for two additional years with the consent of the lenders upon payment of an extension fee equal to 3.0% of the then-outstanding principal amount. The KLIM Credit Agreement also permits the Company to obtain, on a post-closing basis, a separate revolving credit facility of up to $75.0 million from one or more commercial banks. Any such revolving facility would not be documented under the KLIM Credit Agreement, but would be secured by a first-priority lien on the Company's collateral, senior to the lien securing the KLIM Facility, and would be subject to an inter-creditor agreement between the lenders. As of September 30, 2026, no such revolving credit facility had been established.

Turtle Creek Gas and certain other subsidiaries of the Company, including Hallador Power and Sunrise Coal, guarantee the obligations under the KLIM Facility. The obligations are secured by a first-priority perfected security interest in substantially all real and personal property of the Company, Turtle Creek and the subsidiary guarantors, including the equity interests of their subsidiaries (other than subsidiaries designated as unrestricted subsidiaries under the KLIM Credit Agreement), the Turtle Creek Project, the Merom Station, and certain mining assets of Sunrise Coal, subject to customary exceptions and, upon establishment of the revolving credit facility described above, an inter-creditor agreement.

Prior to the date the Turtle Creek Project achieves commercial operation (the "Commercial Operation Date"), borrowings bear interest at (i) a fixed rate of 3.5% per annum, payable in cash, plus (ii) Term SOFR plus 4.5% per annum, which is paid-in-kind ("PIK") by adding such interest to the outstanding principal balance. On and after the Commercial Operation Date, borrowings bear interest at Term SOFR plus 8.0% per annum, payable in cash. Term SOFR is subject to a floor of 3.5%. As of September 30, 2026, the interest rate on borrowings under the KLIM Facility was 11.9%, and the effective interest rate, including the amortization of debt issuance costs, was 14.7%. On the KLIM Closing Date, Turtle Creek made an intercompany loan of $19.7 million to the Company to fund cash collateral for the Company's outstanding letters of credit (the "Closing Date Intercompany Loan"). Under the KLIM Credit Agreement, the PIK interest rate on the KLIM Facility increases by 1.0% per annum if the Closing Date Intercompany Loan remains outstanding after October 31, 2026, and by an aggregate of 3.0% per annum if it remains outstanding after January 15, 2027, in each case until the loan is repaid in full. The Closing Date Intercompany Loan was not repaid by October 31, 2026, and as a result, effective November 1, 2026, the PIK interest rate on the KLIM Facility increased by 1.00% per annum. As of the date of this Quarterly Report, the loan remains outstanding. The Company is required to pay its excess cash flow for fiscal year 2026 and each fiscal year thereafter (calculated excluding Turtle Creek and its subsidiaries and including the net proceeds of equity issuances and permitted convertible indebtedness) into the construction account to repay the Closing Date Intercompany Loan until it is repaid in full.

Upon repayment in full of the term loans, whether at maturity, upon acceleration, or otherwise, the Company is required to pay a premium to the extent necessary for each lender to have received cash payments and outstanding principal (including PIK interest) equal to at least 1.35 times its funded term commitment, increasing to 1.50 times if the maturity date is extended (the "MOIC Premium"). The MOIC Premium is not accrued as of September 30, 2026 because payment is contingent on a repayment or acceleration event that was not probable at the balance sheet date.

Prior to the Commercial Operation Date, no scheduled principal payments are required. Beginning with the first full fiscal quarter after the Commercial Operation Date, the Company is required to make quarterly principal payments equal to 0.25% of the original principal amount of the term loans. Beginning with the first full fiscal year ending after the Commercial Operation Date, the Company is required to prepay the term loans with 100.0% of Consolidated Excess Cash Flow, as defined in the KLIM Credit Agreement. The KLIM Facility also requires mandatory prepayments from the net proceeds of certain asset dispositions and casualty events in excess of $2.5 million, subject to reinvestment rights, and from the proceeds of indebtedness not permitted under the KLIM Credit Agreement.

Proceeds from the initial term loan were used to (i) repay in full and terminate the TCB Credit Facility, including $100.9 million of outstanding principal and interest, as described below, (ii) reimburse the Company for $41.0 million of Turtle Creek Project costs previously funded by the Company, (iii) fund $19.7 million of cash collateral supporting the

Company's outstanding letters of credit, (iv) fund the costs of developing and constructing the Turtle Creek Project, including payments due under the Company's Asset Purchase Agreement (the "APA") with Energy World Corporation Ltd. (the "Seller") as described in *"Note 15 - Commitments and Contingencies,"* and (v) pay transaction fees and expenses and fund general corporate purposes. Turtle Creek Project funds are held in a construction account subject to a deposit account control agreement in favor of the collateral agent, from which disbursements may be made only upon approval of the administrative agent. Amounts held in the construction account and the letter of credit cash collateral accounts are presented as restricted cash in the condensed consolidated balance sheet.

In connection with the KLIM Facility, the Company incurred debt issuance costs of $26.2 million, consisting of $15.0 million of fees paid to the lenders, including a 2.5% commitment fee, and $11.2 million of third-party costs, including financial advisory, legal, and agency fees. These costs are presented as a reduction of the carrying amount of the debt and are amortized to interest expense using the effective interest method over the term of the KLIM Facility.

TCB Credit Facility

On March 5, 2026, Hallador entered into a credit agreement with Texas Capital Bank, as administrative agent, and Old National Bank, among others, (the "TCB Credit Agreement") that replaced the credit agreement with PNC Bank, National Association, ("PNC") and included a $75.0 million senior secured revolving credit facility (the "TCB Revolving Credit Facility") and a $45.0 million senior secured term loan facility (the "TCB Delayed Draw Term Loan", and together with the TCB Revolving Credit Facility, the "TCB Credit Facility").

On April 21, 2026 and June 25, 2026, the Company entered into the First and Second Amendments to the TCB Credit Agreement, respectively, which among other things made certain administrative and technical modifications and modified certain financial covenants.

On the KLIM Closing Date, the Company used proceeds from the KLIM Facility to repay in full the TCB Credit Facility, including $100.2 million of outstanding principal, consisting of $45.0 million under the term loan and $55.2 million under the revolving credit facility, and $0.7 million of accrued interest, and the TCB Credit Facility was terminated. The repayment was accounted for as a debt extinguishment. The Company recognized a loss on extinguishment of debt of $5.7 million during the three months ended September 30, 2026, largely consisting of the write-off of unamortized debt issuance costs related to the TCB Credit Facility, and $5.9 million during the nine months eneded September 30, 2026, which also includes $0.2 million related to the the PNC credit agreement recognized in the first quarter.

PNC Credit Agreement

The Company was party to a credit agreement with PNC, in its capacity as administrative agent, which consisted of a revolving credit facility of up to $75.0 million and a term loan ("PNC Credit Agreement").

On June 27, 2025, the Company executed the Third Amendment ("Third Amendment") to the PNC Credit Agreement, 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 and deferring certain covenants until the third quarter of 2025. During the third quarter of 2025, the Company entered into a $35.0 million prepaid forward power sales contract of which $19.0 million of the proceeds were deposited into a money market account with the administrative agent as a compensating balance. The compensating balance was utilized to fully repay the outstanding term loan during the fourth quarter of 2025. As of March 5, 2026, the Company fully repaid its revolving credit facility with PNC.

Liquidity

Liquidity consists of our additional borrowing capacity and unrestricted cash and cash equivalents. As of September 30, 2026, we did not have additional borrowing capacity under the KLIM Facility for general corporate purposes, as the undrawn delayed draw term loan commitment is available only to fund the Turtle Creek Project. Total liquidity was $103.2 million.

Fees

Bank fees and other costs incurred in connection with the KLIM Facility totaled $26.2 million and are amortized over the term of the KLIM Facility. Unamortized bank fees as of September 30, 2026, and December 31, 2025, were $26.0 million and $0.3 million, respectively.

Unamortized bank fees and other costs incurred in connection with our prior credit agreements of $5.9 million were recorded as a loss on extinguishment of debt on the condensed consolidated statements of operations for the nine months ended September 30, 2026.

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

	September 30, 2026	December 31, 2025
Total debt	$ 551,924	$ 30,000
Less total unamortized debt issuance cost	(25,959)	(322)
Net debt	$ 525,965	$ 29,678

All debt was classified as long-term at September 30, 2026 and December 31, 2025.

Future maturities of debt as of September 30, 2026, are as follows (in thousands):

2026	$ —
2027	—
2028	—
2029	551,924
Total	$ 551,924

The amounts above reflect scheduled amortization based on the Company's expected Commercial Operation Date in the second half of 2028 and exclude any mandatory prepayments from Consolidated Excess Cash Flow, additional PIK interest to be accrued after September 30, 2026, the MOIC Premium, and the Company's potential refinancing of the KLIM Facility prior to its scheduled maturity.

Covenants

The KLIM Credit Agreement contains financial covenants that require the Company, beginning with the test period ending December 31, 2026, to maintain (i) unrestricted cash of not less than $10.0 million and (ii) a Consolidated Debt Service Coverage Ratio (as defined in the KLIM Credit Agreement) of not less than 1.15 to 1.00. Beginning with the first full fiscal quarter ending after the Commercial Operation Date, the Company is also required to maintain a Consolidated Leverage Ratio (as defined in the KLIM Credit Agreement) not to exceed 9.00 to 1.00 for the first tested period and 8.00 to 1.00 for each period thereafter. The debt service coverage ratio and leverage ratio covenants are subject to equity cure rights, which may be exercised in no more than two of any four consecutive fiscal quarters and no more than three times over the term of the KLIM Facility. The minimum unrestricted cash covenant is not subject to a cure right.

The KLIM Credit Agreement also contains customary affirmative and negative covenants, including limitations on the occurrence of indebtedness and liens, investments, asset sales, restricted payments, and affiliate transactions, and requires Turtle Creek to maintain an independent manager. Events of default include, among others, nonpayment, covenant breaches (subject to applicable cure periods), cross-default to other indebtedness in excess of $15.0 million, judgments in excess of $25.0 million, a change of control, and the failure of the Turtle Creek Project to achieve the Commercial Operation Date on or before June 30, 2029. Upon an event of default, the lenders may accelerate the outstanding obligations, and the MOIC Premium would become payable.

The KLIM Credit Agreement restricts the ability of Turtle Creek and its subsidiaries to pay dividends, make distributions, or make loans or advances to the Company, other than certain permitted payments, including the reimbursement of up to $43.0 million of Turtle Creek Project costs and an intercompany loan of up to $20.0 million made at closing. As of September 30, 2026, the Company was in compliance with all covenants under the KLIM Credit Agreement. The test period for financial covenants does not begin until December 31, 2026.

Interest Expense

Interest expense from the KLIM Facility consisted of the following (in thousands):

	Three and Nine Months Ended September 30, 2026
Cash interest	$ 801
PIK interest	1,924
Amortization of debt issuance costs	234
Less: capitalized interest	(233)
Interest expense included in the condensed consolidated statements of operations	$ 2,726

Interest incurred on the KLIM Facility during the construction of the Turtle Creek Project is capitalized as part of the cost of the Turtle Creek Project. PIK interest of $1.9 million and the repayment of the TCB Facility directly by the lenders on behalf of the Company of $100.2 million were noncash activities during the nine months ended September 30, 2026.

Interest capitalized to the Turtle Creek Project totaled $0.5 million on the TCB Credit Facility and $0.2 million on the KLIM Facility, or $0.7 million in total, for the three and nine months ended September 30, 2026.

Fair Value

The KLIM Facility was funded on September 15, 2026 at interest rates, including a floating Term SOFR-based component, negotiated at arm's length with unrelated lenders. Accordingly, the Company believes the fair value of its debt approximates its principal amount as of September 30, 2026. The fair value of the Company's debt is classified within Level 2 of the fair value hierarchy.

(6) ACCRUED LIABILITIES AND OTHER

Accrued liabilities and other consist of the following for the indicated dates (in thousands):

	September 30, 2026	December 31, 2025
Accrued liabilities	18,039	10,829
Workers' compensation reserve	5,617	5,223
Accrued property taxes	4,384	3,900
Accrued payroll	4,574	3,037
ARO - current portion	2,155	2,606
Group health insurance	1,393	1,420
Operating lease liability - current portion	628	—
Other	2,376	2,239
Total accrued liabilities and other	$ 39,166	$ 29,254

(7) REVENUE

Revenue from Contracts with Customers

We account for contracts with customers 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 that 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

For Power Purchase Agreements ("PPA") that are not determined to be leases or derivatives, we have concluded that a contract exists when the PPA is executed by the parties, as this is the point at which enforceable rights and obligations are established.

Under accredited capacity PPAs, we recognize revenue daily, based on an output method of capacity made available as part of any stand-ready obligations for contracted accredited capacity performance obligations. For delivered energy PPAs, we recognize revenue daily for the actual delivered MWh of electricity. For the prepaid delivered energy PPAs, we recognize revenue daily for the funds received for the actual delivered MWh of electricity plus any accretion attributable to the time value of money.

When there is an outage at one of the generating units at Merom or energy hours at the Merom Hub are priced below our production cost, we have the option to make net hourly purchases of power in the MISO market to satisfy our obligations, which we record as cost of purchased power in our condensed consolidated statements of operations.

Coal operations

Our coal revenue is derived from sales to customers of coal produced at our mining facilities. Our customers typically purchase coal free on board from our mine sites where title, risk of loss, and control pass to the customer. 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. Coal sales agreements with our customers are fixed-priced, fixed-volume supply contracts, but some include a pre-determined escalation in price for each year and some allow for our customers to vary the fixed-volume by pre-determined quantities during a set period, such as quarterly. The terms of our coal sales agreements result from extensive, competitive negotiations with customers. Consequently, the terms of these contracts vary by customer.

Coal sales agreements typically contain coal quality specifications which require the raw coal sold by us to the customer to be (i) substantially free of magnetic material and other foreign material impurities and (ii) 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 British thermal unit factor, moisture, ash, and sulfur content, and can result in either increases or decreases in the value of the coal shipped. When applicable, we have constrained the expected value of variable consideration in our estimation of transaction price and only included this consideration to the extent that it is probable that a significant revenue reversal will not occur.

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,	
	2026	2025	2026	2025
Delivered energy (including contract liability amortization)	$ 74,169	$ 77,776	$ 167,313	$ 194,044
Accredited capacity	18,677	15,459	52,819	45,110
Total Electric Operations sales	$ 92,846	$ 93,235	$ 220,132	$ 239,154

Coal Operations

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
Third party Indiana customers	$ 23,457	$ 27,355	$ 78,072	$ 68,960
Third party other customers	12,671	23,901	33,737	50,628
Total Coal Operations sales	$ 36,128	$ 51,256	$ 111,809	$ 119,588

Performance Obligations

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.

Electric Operations

We concluded that each MWh of delivered energy is capable of being distinct as a customer could benefit from each on its own by using 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 accredited capacity provides an economic benefit to the holder and could be sold by the customer.

Coal Operations

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 using 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, 2026, disaggregated by segment and contract duration (in thousands).

	2026	2027	2028	2029	2030	Thereafter	Total
Delivered energy revenue	$ 56,279	$ 160,255	$ 86,570	$ 28,931	$ —	$ —	$ 332,034
Accredited capacity revenue	16,315	75,310	90,951	102,374	87,539	824,777	1,197,265
Coal Operations revenue[1]	51,252	159,845	44,625	—	—	—	255,721
Total revenue	$ 123,845	$ 395,409	$ 222,146	$ 131,304	$ 87,539	$ 824,777	$ 1,785,020

1 - Coal Operations revenue consists of consolidated revenue excluding our intercompany revenues from Merom.

Subsequent to September 30, 2026, on October 7, 2026, the Company entered into two agreements, a six-year Power Purchase Agreement (the "Energy PPA") and an agreement under a Master Power Purchase and Sale Agreement (the "Capacity PPA") with an Indiana utility provider ("Indiana Utility"). The Energy PPA and Capacity PPA are not included in the table above. Both agreements run from June 1, 2029 through May 31, 2035. The Energy PPA has an annual average base energy quantity of 200 MW of electricity from the Merom Station. Under the Capacity PPA, the Company will sell the Indiana Utility an annual average of 225 Zonal Resource Credits per day, which represent accredited generating capacity under MISO rules and will be sourced exclusively from the Merom Station's two generating units.

Contract Balances

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 accredited 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. When the Company receives customer payments more than one year in advance of the related performance obligations and the financing is significant in the context of the contract, the Company adjusts the transaction price for the significant financing component associated with these contracts at risk adjusted market rates. The resulting interest accretion is recognized as interest expense over the period between the customer payment date and the expected satisfaction of the performance obligation.

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

	September 30,	
	2026	2025
Accounts receivable from contracts with customers - beginning balance	$ 13,989	$ 15,438
Accounts receivable from contracts with customers - ending balance	$ 23,169	$ 24,763

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

	September 30,	
	2026	2025
Total contract liabilities - beginning balance	$ 149,057	$ 146,719
Cash payments received on future contract obligations	67,880	102,480
Accretion on contract liabilities	7,027	5,659
Revenue recognized, cash payment received in prior period	(86,806)	(82,639)
Revenue recognized, cash payment received in current period	(23,427)	(24,613)
Total contract liabilities - ending balance	$ 113,730	$ 147,606

(8) INCOME TAXES

For the nine months ended September 30, 2026 and 2025, 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, 2026 and 2025, was approximately 0%. The three months ended September 30, 2026 include income tax expense of $1.8 million related to a change in our estimated annual effective tax rate, which resulted from a decrease in forecasted full-year pretax income, now a pretax loss. Historically, our actual effective tax rates 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 by accelerating deductions for tax purposes. As the more significant benefits relate to the timing of deductions, there were no material impact affecting the effective tax rate or the valuation allowance determination in the period that OBBBA was enacted.

(9) STOCK COMPENSATION PLANS

Non-vested grants and activity for the period presented are as follows (in whole shares):

Non-vested grants as of December 31, 2025	586,101
Awarded	314,166
Vested	(212,849)
Forfeited	(4,452)
Non-vested grants as of September 30, 2026	682,966

For the three and nine months ended September 30, 2026, our stock compensation expense was $1.2 million and $3.7 million, respectively. For the three and nine months ended September 30, 2025, our stock compensation expense was $0.6 million and $2.1 million, respectively.

Non-vested restricted stock unit ("RSU") grants will vest as follows (in whole shares):

Vesting Year	RSUs Vesting
2026	12,173
2027	459,273
2028	163,823
2029	47,697
	682,966

As of September 30, 2026, unrecognized stock compensation expense to be recognized over the respective vesting period is $5.9 million, and we had 1,782,203 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. 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, 2026 or December 31, 2025.

The Company also self-insures for a portion of its 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. As of September 30, 2026 and December 31, 2025, the Company has restricted cash of $4.2 million and $3.0 million, respectively, for future workers' compensation claim payments. The Company had $5.6 million and $5.2 million of workers' compensation reserve as of September 30, 2026 and December 31, 2025, respectively, in 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.

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.

The carrying amounts for cash equivalents, accounts receivable, accounts payable, accrued liabilities and other, approximate fair value due to the short maturity of those instruments. Our debt is recorded at amortized cost. As described in *"Note 5 – Debt,"* its fair value approximates its principal amount and is classified within Level 2 of the fair value hierarchy. Our debt is collateralized primarily by our assets.

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 totaled $433.0 million and $15.4 million as of September 30, 2026 and December 31, 2025, 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 which owns gas reserves and gathering equipment with plans to develop and operate such reserves. Sunrise Energy 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 was $2.1 million and $1.9 million as of September 30, 2026 and December 31, 2025, 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, 2026 and December 31, 2025, was $0.5 million and $0.7 million, respectively.

(13) 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 the Merom Station, which is a two-unit, 1,080-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 accredited 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 approximated market prices at the time the prices were agreed.

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. Revenue from our Coal Operations segment consists of sales of coal to various third parties and to the Merom Station. Coal sales to our Electric Operations are based on multi-year contracts that approximated market prices at the time the prices were agreed. Intercompany coal sales and amounts above actual costs to produce the coal are eliminated in the condensed 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 Segment EBITDA for each business segment. Segment EBITDA is calculated for each segment as follows:

1. For our Electric Operations segment, Segment EBITDA is comprised of accredited capacity and delivered energy revenues less certain significant segment expenses, which include (i) variable costs 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, Segment EBITDA 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.

Segment EBITDA 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, Segment EBITDA 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 segment's operations.

Presented below are the Electric and Coal Operations key metrics reviewed by the CODM for the three months ended September 30, 2026 and 2025 (in thousands):

	Three Months Ended September 30,			
	2026		2025	
	Electric Operations	Coal Operations	Electric Operations	Coal Operations
Delivered energy	$ 74,169	$ —	$ 77,776	$ —
Accredited capacity revenue	18,677	—	15,459	—
Coal sales	—	50,631	—	68,814
Total Sales	92,846	50,631	93,235	68,814
Fuel	(43,440)	(779)	(44,751)	(574)
Other operating costs[1]	—	—	(1)	—
Total variable costs	(43,440)	(779)	(44,752)	(574)
Other operating and maintenance costs[2]	(7,093)	(24,482)	(9,368)	(35,046)
Cost of purchased power	(11,103)	—	(2,074)	—
Utilities	(2,291)	(2,817)	(1,873)	(2,670)
Labor	(9,798)	(20,690)	(7,949)	(19,625)
Segment margin without general and administrative	19,121	1,863	27,219	10,899
General and administrative	(1,508)	(2,397)	(1,308)	(2,062)
Segment EBITDA	$ 17,613	$ (534)	$ 25,911	$ 8,837

Presented below are the Electric and Coal Operations key metrics reviewed by the CODM for the nine months ended September 30, 2026 and 2025 (in thousands):

	Nine Months Ended September 30,			
	2026		2025	
	Electric Operations	Coal Operations	Electric Operations	Coal Operations
Delivered energy	$ 167,313	$ —	$ 194,044	$ —
Accredited capacity revenue	52,819	—	45,110	—
Coal sales	—	147,917	—	169,117
Total Sales	220,132	147,917	239,154	169,117
Fuel	(96,258)	(2,093)	(104,150)	(1564)
Other operating costs[1]	(1)	—	(10)	—
Total variable costs	(96,259)	(2,093)	(104,160)	(1,564)
Other operating and maintenance costs[2]	(32,252)	(67,582)	(24,602)	(77,147)
Cost of purchased power	(34,599)	—	(11,086)	—
Utilities	(6,387)	(8,695)	(3,932)	(9,270)
Labor	(26,549)	(60,139)	(23,731)	(57,671)
Segment margin without general and administrative	24,086	9,408	71,643	23,465
General and administrative	(4,299)	(6,826)	(3,972)	(6,290)
Segment EBITDA	$ 19,787	$ 2,582	$ 67,671	$ 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 included in fuel and other operating costs.

Presented below are the Electric and Coal Operations revenues reconciled to our consolidated operating revenues for the three months ended September 30, 2026 (in thousands):

Reconciliation of Revenue:	Electric Operations	Coal Operations	Corporate and Other and Eliminations	Consolidated
Delivered energy	$ 74,169	$ —	$ —	$ 74,169
Accredited capacity revenue	18,677	—	—	18,677
Other operating revenue	149	696	431	1,276
Coal sales (third party)	—	36,128	—	36,128
Coal sales (intercompany)	—	14,503	(14,503)	—
Operating Revenue	$ 92,995	$ 51,327	$ (14,072)	$ 130,250

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
Accredited capacity revenue	15,459	—	—	15,459
Other operating revenue	170	1,582	314	2,066
Coal sales (third party)	—	51,256	—	51,256
Coal sales (intercompany)	—	17,558	(17,558)	—
Operating Revenue	$ 93,405	$ 70,396	$ (17,244)	$ 146,557

Presented below are the Electric and Coal Operations revenues reconciled to our consolidated operating revenues for the nine months ended September 30, 2026 (in thousands):

Reconciliation of Revenue:	Electric Operations	Coal Operations	Corporate and Other and Eliminations	Consolidated
Delivered energy	$ 167,313	$ —	$ —	$ 167,313
Accredited capacity revenue	52,819	—	—	52,819
Other operating revenue	517	2,624	1,161	4,302
Coal sales (third party)	—	111,809	—	111,809
Coal sales (intercompany)	—	36,108	(36,108)	—
Operating Revenue	$ 220,649	$ 150,541	$ (34,947)	$ 336,243

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
Accredited capacity revenue	45,110	—	—	45,110
Other operating revenue	3,372	4,206	786	8,364
Coal sales (third party)	—	119,588	—	119,588
Coal sales (intercompany)	—	49,529	(49,529)	—
Operating Revenue	$ 242,526	$ 173,323	$ (48,743)	$ 367,106

Presented below is the summary of Segment EBITDA (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
Electric Operations	$ 17,613	$ 25,911	$ 19,787	$ 67,671
Coal Operations	(534)	8,837	2,582	17,175
Total Segment EBITDA	$ 17,079	$ 34,748	$ 22,369	$ 84,846

Presented below is our reconciliation of Segment EBITDA to the most comparable GAAP account, income (loss) before income taxes (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
Segment EBITDA	$ 17,079	$ 34,748	$ 22,369	$ 84,846
All other	980	648	3,065	(1,207)
Other operating revenue	1,276	2,066	4,302	8,364
Depreciation, depletion and amortization	(7,623)	(9,142)	(28,134)	(29,661)
ARO accretion	(427)	(446)	(1,251)	(1,310)
Exploration costs	(36)	(38)	(407)	(157)
Gain (loss) on disposal or abandonment of assets, net	(343)	2,334	(157)	2,410
Interest income	855	289	1,281	416
Interest expense	(6,007)	(4,927)	(13,753)	(12,469)
Loss on extinguishment of debt	(5,717)	—	(5,947)	—
Equity method investment (loss)	358	(248)	(7)	(287)
Corporate — general and administrative	(3,066)	(1,400)	(10,256)	(8,834)
Income (Loss) before Income Taxes	$ (2,671)	$ 23,884	$ (28,895)	$ 42,111

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[1]	Corporate and Other and Eliminations	Consolidated
Assets at September 30, 2026	$ 686,825	$ 153,856	$ 68,060	$ 908,741
Assets at December 31, 2025	$ 256,529	$ 148,957	$ 2,567	$ 408,053
Capital Expenditures for the nine months ended September 30, 2026	$ 78,644	$ 12,436	$ —	$ 91,080
Capital Expenditures for the nine months ended September 30, 2025	$ 25,369	$ 18,908	$ —	$ 44,277

1 As of December 31, 2025, Coal Operations assets included $9.4 million of cash and cash equivalents held on behalf of the consolidated group, consisting of funds transferred from Electric Operations and Hallador for centralized treasury management purposes. During the third quarter of 2026, this cash was transferred to Corporate and Other. The December 31, 2025 presentation is not reflective of Coal Operations' earnings capacity; refer to the condensed consolidated balance sheets.

(14) 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 presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
Basic earnings per common share:				
Net income (loss) - basic	$ (4,497)	$ 23,884	$ (29,053)	$ 42,111
Weighted average shares outstanding - basic	47,145	43,007	46,937	42,869
Basic earnings (loss) per common share	$ (0.10)	$ 0.56	$ (0.62)	$ 0.98

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,	
	2026	2025	2026	2025
Diluted earnings per common share:				
Net income (loss) - diluted	$ (4,497)	$ 23,884	$ (29,053)	$ 42,111
Weighted average shares outstanding - basic	47,145	43,007	46,937	42,869
Add: Dilutive effects of Restricted Stock Units	—	427	—	418
Weighted average shares outstanding - diluted	47,145	43,434	46,937	43,287
Diluted net income (loss) per share	$ (0.10)	$ 0.55	$ (0.62)	$ 0.97

The computation of diluted net loss per share for the three and nine months ended September 30, 2026 excludes 273,538 and 320,469 potentially dilutive securities, respectively, related to unvested restricted stock units as their inclusion would have been anti-dilutive.

(15) COMMITMENTS AND CONTINGENCIES

Commitments

Asset Purchase Agreement — Turbine Equipment

On May 30, 2026, the Company entered into an APA with the Seller to acquire approximately 460 MW of Siemens gas turbines, generators, a steam turbine, and ancillary equipment for a total purchase price of $350.0 million. The Company expects to incur approximately $100.0 million of additional costs for transportation, refurbishment, insurance, and logistics in connection with the delivery of the equipment.

The Company paid $23.8 million to third party vendors on behalf of the Seller during the nine months ended September 30, 2026 which is included in construction work in progress on the condensed consolidated balance sheets. As of September 30, 2026, the remaining purchase price under the APA was approximately $326.2 million. In October 2026, the Company made the third and fourth installment payments under the APA totaling $315.0 million consisting of a $50.0 million payment to the Seller and a $265.0 million payment into an escrow account held by the Seller, and paid an additional $11.0 million to the Seller and to third party vendors on behalf of the Seller. The October payments were paid from Turtle Creek funds, including the construction account established under the KLIM Facility. See *"Note 5 – Debt."* As of October 31, 2026, the Company had paid $349.8 million of the $350.0 million purchase price. In October 2026, the equipment was loaded onto an ocean-going vessel, which departed the Philippines and title to the equipment transferred to the Company.

Other

Our Coal Operations subsidiary was party to litigation in which the plaintiffs alleged violations of the Fair Labor Standards Act and state law due to alleged failure to compensate for time "donning" and "doffing" equipment and to account for certain bonuses in the calculation of overtime rates and pay. In 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, we transferred $2.7 million into an escrow account and in late 2025 the settlement terms were approved by the court. At September 30, 2026, there were no further amounts accrued on our consolidated balance sheet related to this litigation.

(16) AT MARKET AGREEMENT AND CONFIDENTIALLY MARKETED PUBLIC OFFERING

ATM

On December 18, 2023, the Company entered into an At Market Issuance Sales Agreement (the “Sales Agreement”) with B. Riley Securities, Inc. (the “Agent”), under which the Company could issue and sell, from time to time, shares of its common stock, par value $0.01 per share (the “Common Stock”), with aggregate gross proceeds of up to $50.0 million through an “at-the-market” equity offering program under with the Agent acting as sales agent (the “ATM Program”). Either the Company or the Agent could terminate the Sales Agreement, in its sole discretion, by giving five days’ notice. On December 16, 2025, the Company amended the Sales Agreement to increase the aggregate gross sales proceeds under the ATM Program from $50.0 million to $100.0 million.

During the first quarter of 2026, we issued 10,832 shares of Common Stock under the ATM Program for net proceeds of $0.2 million. During the year ended December 31, 2025, we issued 697,227 shares of Common Stock under the ATM Program for net proceeds of $13.5 million. In January 2026, the Company delivered written notice to the Agent to terminate the Sales Agreement effective January 18, 2026. As a result of the termination of the Sales Agreement, the Company will not offer or sell any further shares under the ATM Program.

CMPO

In January 2026, the Company conducted a confidentially marketed public offering (the "CMPO") pursuant to a base prospectus and a final prospectus supplement that were filed with the SEC. The Company sold a total of 3,194,444 shares of Common Stock, at a price to the public of $18.00 per share for aggregate gross proceeds of approximately $57.5 million, including the exercise of the underwriter’s option prior to deducting underwriting discounts, commissions, and other offering expenses of $3.7 million.

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

The following discussion and analysis included in our Annual Report on Form 10-K for the year ended December 31, 2025 (the "2025 10-K"), is intended to assist in providing an understanding of changes in our results of operations and financial condition and is organized as follows:

- Forward-Looking Statements. This section provides a description of certain factors that could cause actual results or events to differ materially from anticipated results or events.
- Overview. This section provides a general description of our business and recent events.
- Material Changes in Results of Operations. This section provides an analysis of our results of operations for the three and nine months ended September 30, 2026 and 2025.
- Material Changes in Financial Condition. This section provides an analysis of our liquidity and our condensed consolidated statements of cash flows.

The capitalized terms used below have been defined in the notes to our condensed consolidated financial statements. In the following text, the terms "we," "our," "the Company" and "us" may refer, as the context requires, to Hallador Energy Company ("Hallador") or collectively to Hallador and its subsidiaries.

Unless otherwise indicated, operational data is presented as of September 30, 2026.

FORWARD-LOOKING STATEMENTS

Certain statements and information in this Quarterly Report on Form 10-Q may constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, which are intended to be covered by the safe harbor provisions of those sections. These statements are based on our beliefs as well as assumptions made by, and information currently available to us. When used in this document, the words "anticipate," "believe," "continue," "could," "estimate," "expect," "forecast," "intend," "may," "plan," "potential," "project," "should," "target," "will," "would," and similar expressions or the negative thereof 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, as well as statements regarding the development, financing, cost, timing, and completion of our 460 MW natural gas-fired peaking generation facility in Sullivan County, Indiana (the "Turtle Creek Project"); the delivery, financing, and deployment of the turbine equipment we have agreed to acquire and the related expansion of the Merom Generating Station (the "Merom Station"); the potential refinancing of our senior secured term loan facility entered into on September 15, 2026 with Kennedy Lewis Investment Management LLC ("KLIM") and the other lenders party thereto (the "KLIM Facility"); our contracted forward sales position and the revenue we expect to realize from it; the anticipated terms, effects, and regulatory approval of our power purchase and capacity agreements; the estimated useful life of the Merom Station; and our evaluation of strategic transactions are forward-looking statements. These statements reflect our current views with respect to future events as of the date of this Quarterly Report on Form 10-Q 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 expressed or implied 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, natural gas and electricity commodity costs, inflation and economic conditions that impact demand of our customers and our operating results;
- the outcome or escalation of current international hostilities;
- changes in competition, or changes in electricity, natural gas or coal prices, demand, and availability which could affect our operating results and cash flows;
- risks associated with the expansion of our operations and properties, including through acquisitions and other strategic transactions, which may not be completed on anticipated terms, or at all;
- risks relating to our ability to fund and perform our obligations under the Asset Purchase Agreement (the "APA") with Energy World Corporation Ltd. for the acquisition of turbine equipment, including the sufficiency of the proceeds of the KLIM Facility and our ability to secure any additional financing for the remaining purchase price and related costs on a timely basis or at all, and the risk of default, forfeiture of amounts paid, or termination of the related agreements if we are unable to do so;

- risks relating to the international and domestic transportation, refurbishment, and delivery of the turbine equipment acquired under the APA, including delays, damage or loss in transit, and costs that exceed our current estimates;
- risks that we may be unable to deploy the turbine equipment acquired under the APA as planned, including because the Midcontinent Independent System Operator ("MISO") does not approve our Expedited Resource Addition Study ("ERAS") application or the related expansion project does not otherwise proceed, which could require us to sell the project together with the equipment or sell the equipment on a standalone basis, potentially at a loss;
- risks relating to our ability to participate in the MISO ERAS program, which ultimately requires the approval of MISO of our application and is a capital intensive project subject to construction, operational, financial, regulatory and legal risks that could impact the project's viability and/or timeline;
- risks relating to our ability to secure agreements in support of the development and construction of planned projects, including the expansion of the Merom Station through the ERAS program;
- risks relating to the development, financing, construction, commissioning, and operation of the Turtle Creek Project, including cost overruns from equipment, materials, labor or other expenses; delays; the performance of contractors, equipment suppliers, and other counterparties; the availability and cost of natural gas supply and pipeline transportation; permitting, interconnection, and other regulatory requirements; and our ability to achieve the Commercial Operation of the Turtle Creek Project (the date on which it does so, the "Commercial Operation Date") by the date required under the Credit Agreement governing the KLIM Facility (the "KLIM Credit Agreement"), the failure of which would constitute an event of default;
- risks relating to our indebtedness under the KLIM Facility, including its substantial cost, which reflects paid-in-kind ("PIK") interest and the premium payable upon repayment in full of the term loans to the extent necessary for each lender to have received cash payments and outstanding principal (including PIK interest) equal to at least 1.35 times its funded term commitment, increasing to 1.50 times if the maturity date is extended (the "MOIC Premium"); the financial and other covenants thereunder, including minimum unrestricted cash, debt service coverage, and leverage requirements and the limited cure rights available; mandatory prepayments from excess cash flow; increases in the PIK interest rate if the Closing Date Intercompany Loan is not repaid when required; the liens securing the KLIM Facility on substantially all of our assets, including the Merom Station and certain mining assets; restrictions on distributions and transfers of cash from Turtle Creek Gas Holdings, LLC ("Turtle Creek") and its subsidiaries; cross-default provisions; and our ability to refinance the KLIM Facility on or around the Commercial Operation Date on acceptable terms, or at all;
- risks arising from the fact that a portion of our contracted forward sales position is subject to regulatory approval or is based on our estimates rather than fixed commitments, including that the revenue we ultimately realize from our contracts could be materially lower than the amounts we have disclosed;
- 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 ("GHG"), wastewater discharge and effluent limitation guidelines ("ELG"), coal combustion residuals, 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, and the risk that regulatory approvals (including from the Indiana Utility Regulatory Commission) or other conditions required for certain of our contracts are not obtained or satisfied on a timely basis, on acceptable terms, or at all;
- changes in the geopolitical environment in industries in which our customers operate;
- 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, including uncertainty regarding tariffs on imports into the United States, 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 debt agreements or other arrangements, limitations on our access to cash held in restricted and project-level accounts, and those resulting from any future unavailability of financing;
- the effects of any future issuance of debt or equity securities, including dilution to our existing stockholders and the imposition of additional restrictive covenants;
- customer bankruptcies, a decline in customer creditworthiness, or customer cancellations or breaches to existing contracts, including failures to make payments when due;
- customer delays or failure to take coal or electricity under contracts;

- adjustments made in price, volume or terms to existing coal or electricity contracts;
- risks associated with our prepaid delivered energy contracts and other fixed-price commitments, including obligations to deliver electricity at prices that may be below prevailing market prices;
- 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, including challenges in operating an aging coal-fired power plant, unplanned equipment failures, and forced or extended maintenance outages, such as those we experienced in the first half of 2026;
- the risk that the Merom Station may not continue to operate economically through its currently estimated useful life of 2040, including as a result of environmental compliance costs, market conditions, or regulatory changes, which could result in accelerated depreciation or impairment charges;
- 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 natural disasters;
- difficulty in making accurate assumptions and projections regarding landfill and 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 One Big Beautiful Bill Act ("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; and
- other factors, including those discussed in "Item 1A. Risk Factors" in our 2025 10-K (as supplemented by "Part II, Item 1A. Risk Factors" of this Quarterly Report on Form 10-Q) and in our other filings with the Securities and Exchange Commission ("SEC").

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. The foregoing list of factors is not exhaustive, and it is not possible for us to predict or identify all such risks and uncertainties. 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 for the year ended December 31, 2025, as supplemented by "Part II, Item 1A. Risk Factors" of this Quarterly Report on Form 10-Q and our subsequent filings with the SEC. 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 or revise any forward-looking statements to reflect new information, future events or developments, unless required by applicable law. Forward-looking statements speak only as of the date of this Quarterly Report on Form 10-Q or, in the case of any other written or oral statement, the date on which it is made, and you should not place undue reliance on them. 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 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.

OVERVIEW

General

Hallador is a vertically integrated, independent power producer (“IPP”) and fuel company with operations primarily in Indiana. The Company operates across multiple stages of the energy supply chain, from accredited capacity and energy to coal. The Company’s electric operations are located within the MISO footprint. Our operations include Hallador Power Company, LLC ("Hallador Power"), which provides accredited capacity and energy to utilities and other energy market participants through its MISO interconnection, and Sunrise Coal, LLC ("Sunrise"), which mines bituminous coal in Indiana to serve various power plants in the Midwest and Southeast United States.

Operations

Our business is organized based on the services and products we provide in two segments: (i) Electric Operations and (ii) Coal Operations. The Company also holds 50% interests in Sunrise Energy, LLC (“Sunrise Energy”) and Oaktown Gas, LLC (“Oaktown Gas”), which are accounted for using the equity method. Through its operating subsidiaries, the Company delivers three main products to its customers.

Accredited Capacity. Hallador Power, the Company’s wholly owned electric subsidiary, owns and operates the Merom Station, a 1,080 MW coal-fired power generating station, consisting of two steam turbine generators. Unit 1 entered commercial operations in 1982 and Unit 2 in 1983. The units are dispatched through its MISO interconnection. In order to purchase energy through the MISO system, an end user must supply or purchase accredited capacity for an equivalent load. As accredited capacity is primarily available in large quantities from dispatchable sources of energy, such as natural gas and coal-fired power plants, Hallador Power sells accredited capacity to utilities and other energy market participants within the MISO system through Power Purchase Agreements (“PPA”) and other bilateral transactions.

Energy. In addition to accredited capacity, Hallador Power sells wholesale energy to utilities, generation and transmission cooperatives, and other energy market participants within the MISO system through PPAs and other bilateral transactions, and sells on a spot basis in the day-ahead and real-time MISO markets.

Coal. Sunrise, the Company’s wholly owned mining subsidiary, mines coal from reserves found in the Illinois Basin (“ILB”). Coal mined by Sunrise is used as a primary fuel source for generating electricity at various power plants in the Midwest and Southeast United States. In addition, Sunrise has a developed infrastructure for the transport of coal, which is typically sold free on board from the shipping point, including rail networks and truck loading systems, facilitating the efficient movement of the resource from the mine to its customers. Sunrise’s Oaktown Mining Complex is about twenty miles from Merom, enabling Merom and Sunrise to take advantage of low-cost fuel on a delivered basis.

Strategy and Management Focus

We view our business as two integrated operations, “Electric Operations” (our gigawatt Merom power generating station), and “Coal Operations” (our coal mining and coal sales group).

We strive to achieve margin expansion through organic revenue growth and profitability in our operations by negotiating and fulfilling contracts for accredited capacity, wholesale energy, and thermal coal to utilities and other energy market participants. We continue to progress the development of the Turtle Creek Project, while monitoring opportunities to expand the capacity of our electric generation capabilities through further development, or via acquisition. We continue to evaluate other strategic transactions that could add diversification, durability, scale, and geographic expansion opportunities to our Electric Operations. While these opportunities are limited and complex, we believe that Hallador is well-positioned to transform retiring and/or underperforming assets into future opportunities. This will enable us to supply high-demand end users, such as data centers and industrial customers, with minimal impact to retail consumers. In addition, we focus our organic capital investments on strategic maintenance projects to maintain our safe operational performance and improve the reliability of Merom.

As discussed further under *“Material Changes in Financial Condition — Capitalization”* below, we also seek to maintain our debt at levels that provide for attractive equity returns without assuming undue risk.

Recent Developments

Turbine Equipment Acquisition. On May 30, 2026, we entered into an APA with Energy World Corporation Ltd. ("the Seller"), to acquire approximately 460 MW of Siemens gas turbines, generators, a steam turbine, and ancillary equipment for a total purchase price of $350.0 million. In October 2026, the equipment was loaded onto an ocean-going vessel, was exported from the Philippines, and title and control of the equipment transferred to Hallador. In October 2026, we made the third and fourth installment payments under the APA totaling $315.0 million, consisting of a $50.0 million payment to the Seller and a $265.0 million payment into an escrow account held by the Seller. As of October 31, 2026, we had paid $349.8 million of the $350.0 million purchase price, including the escrowed amount, with the remaining approximately $0.2 million payable to third party vendors on behalf of the Seller. We expect to incur approximately $100.0 million of additional costs for transportation, refurbishment, insurance, and logistics in connection with the delivery of the equipment. The equipment supports our proposed expansion of generation capacity through MISO's ERAS program. We retain the flexibility to determine the path that best creates value for shareholders, including advancing the full project, selling the project together with the equipment, or selling the equipment on a standalone basis. See "*Note 15 — Commitments and Contingencies"* to the condensed consolidated financial statements and *"Liquidity and Capital Resources"* below for additional information.

Energy and Capacity PPAs with Duke Energy Indiana. On October 7, 2026, Hallador Power entered into two agreements with Duke Energy Indiana, LLC (the "Indiana Utility"); a six year Power Purchase agreement (the "Energy PPA"), which contains an annual average base energy quantity of 200 MW of electricity from the Merom Station, and an agreement under a Master Power Purchase and Sale Agreement (the "Capacity PPA"), under which Hallador Power will sell the Indiana Utility certain Zonal Resource Credits. Both agreements run from June 1, 2029 through May 31, 2035. See *"Note 7 — Revenue"* to the condensed consolidated financial statements for additional information.

KLIM Facility. On September 15, 2026, Hallador and its wholly-owned subsidiary, Turtle Creek, each as a co-borrower, jointly and severally liable for all obligations thereunder, entered into the KLIM Credit Agreement with KLIM, acting for certain managed or advised funds and accounts, the other lenders from time to time party thereto, U.S. Bank Trust Company, National Association, as administrative agent, and U.S. Bank National Association, as collateral agent. The KLIM Credit Agreement provides for the KLIM Facility, a $600.0 million senior secured term loan facility, with $550.0 million funded at closing and a $50.0 million delayed draw available for 12 months after closing, subject to an agreed draw schedule and funding conditions. The KLIM Facility is secured by substantially all of our assets, including the Merom Station and certain mining assets, requires payment of the MOIC Premium upon repayment, and includes an event of default if the Commercial Operation Date has not occurred on or before June 30, 2029. See "*Note 5 — Debt"* to the condensed consolidated financial statements for additional information.

Turtle Creek Project Summary. The Turtle Creek Project is a 460-MW natural gas-fired peaking generation facility in Sullivan County, Indiana, to be owned and operated by Turtle Creek Gas and expected to reach commercial operation in the second half of 2028. Hallador took title and control of the turbine equipment in October 2026 and completed payment of the third and fourth installments under the APA. The October payments were paid from Turtle Creek funds, including the construction account established under the KLIM Facility. The tables below summarize the project's equipment purchase, capitalized costs and financing, and the change in construction work in progress by project. See *"Note 3 – Restricted Cash," "Note 5 – Debt" and "Note 15 – Commitments and Contingencies."*

Turtle Creek Project *(in millions)*

Equipment purchase under the APA		
Purchase price	$	350.0
Paid through September 30, 2026		23.8
Paid October 1 through October 31, 2026		326.0
Remaining payable to third party vendors on behalf of the Seller		0.2
Other project costs		
Expected transportation, refurbishment, insurance, and logistics costs	$	~100.0
Costs capitalized in construction work in progress at September 30, 2026	$	53.1
Financing and cash		
KLIM Facility, funded September 15, 2026	$	550.0
KLIM Facility, delayed draw term loan commitment (available only for the Turtle Creek Project)		50.0
Construction account (restricted cash) at September 30, 2026		294.0
Cash held by Turtle Creek at October 31, 2026	$	34.1

Construction work in progress *(in millions)*

	9/30/2026	12/31/2025	Change
Turtle Creek Project	$ 53.1	$ 13.6	$ 39.5
Merom, including ELG	34.1	26.1	8.0
Other power projects	4.7	—	4.7
Total	$ 92.0	$ 39.7	$ 52.3

Competition and Other External Factors

We are experiencing competition in both our Electric and Coal Operations. This competition has the potential to drive lower market prices for our products and services. Competitors for our Electric Operations include other power generators who bid into the MISO system, while competitors for our Coal Operations include other mining entities that are able to service our existing and potential customers via truck or rail within the Midwest and Southeast United States.

MATERIAL CHANGES IN RESULTS OF OPERATIONS

Forward Sales Position [1]

	2026	2027	2028	2029	2030	2031 - 2035	2036 - 2040	Total
Power								
Accredited Capacity								
Average daily contracted accredited capacity MW	727	789	768	750	725	697	500	
Average contracted accredited capacity price per MWd	$ 244	$ 262	$ 324	$ 478	$ 502	$ 499	$ 480	
Contracted accredited capacity revenue (in millions)	$ 16.31	$ 75.31	$ 90.95	$ 130.97	$ 132.75	$ 635.49	$ 386.85	$ 1,468.64
Energy [2]								
Contracted MWh (in millions)	1.31	3.59	1.92	1.59	1.41	6.14	—	15.96
Average contracted price per MWh	$ 42.93	$ 44.68	$ 44.99	$ 44.47	$ 47.73	$ 50.91	$ —	
Contracted revenue (in millions)	$ 56.28	$ 160.25	$ 86.57	$ 70.77	$ 67.18	$ 312.47	$ —	$ 753.53
Total Accredited Capacity & Energy Revenue per MWh [3]	$ 46.07	$ 59.16	$ 62.48	$ 69.66	$ 73.26	$ 75.35	NM	$ 68.04
Total Accredited Capacity & Energy Revenue (in millions)	$ 72.59	$ 235.56	$ 177.52	$ 201.75	$ 199.93	$ 947.96	$ 386.85	$ 2,222.16
Coal								
Priced tons - 3rd party (in millions)	0.92	2.79	0.75	—	—	—	—	4.46
Avg price per ton - 3rd party	$ 55.89	$ 57.27	$ 59.50	—	—	—	—	
Contracted coal revenue - 3rd party (in millions)	$ 51.25	$ 159.84	$ 44.63	$ —	$ —	$ —	$ —	$ 255.72
TOTAL CONTRACTED REVENUE (IN MILLIONS) - CONSOLIDATED	$ 123.85	$ 395.41	$ 222.15	$ 201.75	$ 199.93	$ 947.96	$ 386.85	$ 2,477.89
Priced tons - Intercompany (in millions)	1.58	1.50	2.02	2.02	2.02	—	—	9.16
Avg price per ton - Intercompany	$ 51.00	$ 55.00	$ 56.00	57.00	58.00	—	—	
Contracted coal revenue - Intercompany (in millions)	$ 80.78	$ 82.50	$ 113.34	$ 115.37	$ 117.39	$ —	$ —	$ 509.39
TOTAL CONTRACTED REVENUE (IN MILLIONS) - SEGMENT	$ 204.63	$ 477.91	$ 335.49	$ 317.12	$ 317.32	$ 947.96	$ 386.85	$ 2,987.27

[1]Total Forward Sales Position as of September 30, 2026, including the impacts of both the Energy PPA and the Capacity PPA executed on October 7, 2026. Actual revenue related to forward sales positions may differ materially for various reasons, including unit contingencies, price adjustment features for coal quality and cost escalations, volume optionality provisions, including rollover of unfulfilled coal commitments into future periods, and potential force majeure events. Certain contracted forward sales positions included above are subject to approval by the Indiana Utility Regulatory Commission. Forward sales figures in the 2026 column are for the period from October 1, 2026 through December 31, 2026.

[2] The Energy PPA executed October 7, 2026 has an annual average base energy quantity of 200 MW. The contract is unit contingent, such that when one or both power generating units at the Merom Station is not producing energy above a certain threshold, the base quantities are reduced proportionate to the number of power generating units in operation. The contract also contains a volume option that permits the counterparty to reduce the base quantity to zero for a maximum of 90 days per year. For purposes of the table above, we have included management's estimates of the energy quantities and revenue based on comparisons to forward energy curve pricing. For the 2029, 2030, and 2031 - 2035 periods in the table above, we have estimated total energy quantities of 0.9 million MWh, 1.4 million MWh, and 6.1 million MWh, respectively, and estimated revenue of approximately $41.8 million, $67.2 million, and $312.5 million, respectively. These estimates are forward-looking statements and could vary materially from actual volumes and revenue, including variations due to the factors described above.

[3] Total Accredited Capacity & Energy Revenue per MWh combines the average contracted price per MWh for energy with the quotient of the contracted accredited capacity revenue divided by annual generation of 5.2 million MWh per year, which represents annualized average generator verification test capacity (GVTC) multiplied by HNRG's average equipment availability factor (EAF), less 15-20% allowances for sub-optimal conditions. Contracted energy pricing is currently established only through 2035; accordingly, the figure for 2036–2040 is not meaningful as no energy revenue is contracted for that period. The Total column reflects 2026–2035, the period for which both energy and capacity pricing are currently under contract.

NM - Not meaningful

Discussion and Analysis of our Reportable Segments

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 our 50% interests in Sunrise Energy and Oaktown Gas, which we account for using the equity method.

Electric Operations

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
	(in thousands)		(in thousands)	
Delivered Energy	$ 74,169	$ 77,776	$ 167,313	$ 194,044
Accredited Capacity Revenue	18,677	15,459	52,819	45,110
Electric Sales	$ 92,846	$ 93,235	$ 220,132	$ 239,154
Fuel	$ (43,440)	$ (44,751)	$ (96,258)	$ (104,150)
Other Operating Costs [1]	—	(1)	(1)	(10)
Other Operating and Maintenance Costs [2]	(7,093)	(9,368)	(32,252)	(24,602)
Cost of Purchased Power	(11,103)	(2,074)	(34,599)	(11,086)
Utilities	(2,291)	(1,873)	(6,387)	(3,932)
Labor	(9,798)	(7,949)	(26,549)	(23,731)
General and Administrative	(1,508)	(1,308)	(4,299)	(3,972)
Segment EBITDA	17,613	25,911	19,787	67,671
Other Operating Revenue	149	170	517	3,372
Depreciation, Depletion and Amortization	(3,081)	(5,131)	(14,949)	(15,456)
Asset Retirement Obligations Accretion	(137)	(126)	(401)	(369)
Interest Income	620	22	694	41
Interest Expense	(4,138)	(2,585)	(9,501)	(6,208)
Income (Loss) before Income Taxes	$ 11,026	$ 18,261	$ (3,853)	$ 49,051

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
	(in thousands) (per MWh)		(in thousands) (per MWh)	
MWh Generated (in thousands)	1,408	1,530	3,143	3,706
MWh Purchased (in thousands)	145	48	513	264
MWh Sold (in thousands)	1,553	1,578	3,656	3,970
Delivered Energy	$ 47.76	$ 49.29	$ 45.76	$ 48.88
Accredited Capacity Revenue	12.03	9.80	14.45	11.36
Electric Sales	$ 59.79	$ 59.08	$ 60.21	$ 60.24
Fuel	$ (27.97)	$ (28.36)	$ (26.33)	$ (26.23)
Other Operating Costs [1]	—	—	—	—
Other Operating and Maintenance Costs [2]	(4.57)	(5.94)	(8.82)	(6.20)
Cost of Purchased Power	(7.15)	(1.31)	(9.46)	(2.79)
Utilities	(1.48)	(1.19)	(1.75)	(0.99)
Labor	(6.31)	(5.04)	(7.26)	(5.98)
General and Administrative	(0.97)	(0.83)	(1.18)	(1.00)
Segment EBITDA	11.34	16.42	5.41	17.05
Other Operating Revenue	0.10	0.11	0.14	0.85
Depreciation, Depletion and Amortization	(1.98)	(3.25)	(4.09)	(3.89)
Asset Retirement Obligations Accretion	(0.09)	(0.08)	(0.11)	(0.09)
Interest Income	0.40	0.01	0.19	0.01
Interest Expense	(2.66)	(1.64)	(2.60)	(1.56)
Income (Loss) before Income Taxes	$ 7.10	$ 11.57	$ (1.05)	$ 12.36

[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 included in fuel and other operating costs.

Q3 2026 vs. Q3 2025

Segment operating revenues from electric operations decreased $0.4 million, or 0.4%, compared to the third quarter of 2025, attributable to a $3.6 million decrease in sales of delivered energy that was partially offset by a $3.2 million increase in accredited capacity revenue. The price per MWh for delivered energy decreased 3.1% year-over-year from $49.29 for the three-month period ended September 30, 2025 to $47.76 in 2026, primarily attributable to contract mix, driven by increased deliveries under lower-priced prepaid forward sales contracts. Our Electric Operations generated 0.1 million lower MWh, offset by the purchase of an additional 0.1 million MWh for resale resulting in a 1.6% reduction in total MWh sold compared to the third quarter of 2025. Accredited capacity revenue increased 20.8% to $18.7 million for the three-month period ended September 30, 2026 from $15.5 million in the comparable prior year period driven by improved prices.

Fuel costs on a segment basis decreased $1.3 million, or 2.9%, from the third quarter of 2025. The decrease includes a $2.6 million coal inventory adjustment recorded in the third quarter of 2025 that did not recur in 2026, partially offset by higher non-coal fuel costs, primarily fuel oil consumed during the start-ups. Coal costs decreased $0.3 million, due to lower electric power generation of 8.0% and the benefit of the coal mix used, partially offset by a higher burn rate and an increase in the cost of coal consumed of 2.4%, from $54.22 per ton in 2025 to $55.51 per ton in 2026. Fuel costs on a consolidated basis increased $1.6 million, or 6.1%, reflecting a heavier reliance on coal from third-parties combined with a 6.2% increase in the average price per ton of coal purchased from third parties. Weather and natural gas pricing had a muted impact on the demand for coal, as the average spot price at Chicago citygate increased $0.10 per thousand cubic feet to $3.75 per thousand cubic feet in July 2026 compared to July 2025.

Other operating and maintenance costs decreased $2.3 million, or 24.3%, from the third quarter of 2025, primarily because the 2025 planned maintenance outage was phased later in the year with more of the planned maintenance activities extending into the third quarter in 2025 in comparison to the planned maintenance outage in 2026. This was partially offset

by higher consumable supplies and maintenance services associated with unplanned outages during the third quarter of 2026.

Cost of purchased power increased $9.0 million, or 435.3%, from the third quarter of 2025. When there is an outage at one of the generating units at Merom or energy hours at the Merom Hub are priced below our production cost, we have the option to make economic net hourly purchases of power in the MISO market to satisfy our obligations, which we record as cost of purchased power. In 2026, we purchased an incremental 0.1 million MWh compared to 2025, an increase of 202.1% that was further impacted by the energy pricing dynamics at the time of the purchases.

Labor expenses increased $1.8 million or 23.3% for the third quarter of 2026 versus the comparable period in 2025 driven by the impact of incremental maintenance efforts associated with the completion of the 2026 planned major maintenance outage in combination with annual wage increases.

Depreciation, depletion and amortization decreased $2.1 million, or 40.0%, from the third quarter of 2025 as lower depreciation expense from extending the estimated useful lives of the Merom Station and related assets through 2040, was only partially offset by incremental depreciation from recent capital expenditures placed in service. The change in estimated useful life was accounted for prospectively beginning in the second quarter of 2026 as a change in accounting estimate and decreased depreciation expense by $3.6 million for the three months ended September 30, 2026. See *"Note 1 – Basis of Presentation"* to the condensed consolidated financial statements for further information.

Interest expense increased $1.6 million, or 60.1%, from the third quarter of 2025. The increase primarily relates to interest on the KLIM Facility, which was funded on September 15, 2026 ($2.7 million, net of $0.2 million of capitalized interest), partially offset by lower accretion on our prepaid delivered energy contracts ($1.9 million compared to $2.4 million) as the contract liability balance declined. Hallador has not entered into any new prepaid delivered energy contracts in 2026.

Income before income taxes decreased $7.2 million from $18.3 million in the third quarter of 2025 to $11.0 million in the third quarter of 2026, which is attributable to the items described in the discussion above.

YTD 2026 vs. YTD 2025

Segment operating revenues from electric operations for the nine months ended September 30, 2026 decreased $19.0 million, or 8.0% compared to the first nine months of 2025, attributable to a $26.7 million decrease in sales of delivered energy partially offset by a $7.7 million increase in accredited capacity revenue. Our Electric Operations generated 0.6 million fewer MWh, but purchased an additional 0.2 million MWh for resale resulting in a net decrease of energy sales of 0.3 million MWh, a decrease of 7.9% compared to the first nine months of 2025. Lower plant availability in the first half of 2026 due to equipment issues at Merom had a significant impact on the total MWh generated. The impacted generating unit underwent a planned major maintenance outage beginning in May and the unit returned to operation in July. The price per MWh for delivered energy decreased 6.4% year-over-year from $48.88 for the nine-month period ended September 30, 2025 to $45.76 in 2026. Accredited capacity revenue increased 17.1% to $52.8 million for the nine-month period ended September 30, 2026 from $45.1 million in the comparable prior year period.

Fuel costs on a segment basis decreased $7.9 million, or 7.6%, from the first nine months of 2025. The decrease is due to electric power generation falling by 0.6 million MWh, or 15.2%. We consumed 0.2 million fewer tons of coal on both a segment and consolidated basis in 2026 compared to 2025. Equipment issues experienced during the first quarter of 2026 accounted for 0.5 million MWh of the 0.6 million MWh decline in generation for the nine months ended September 30, 2026. The decrease was partially offset by an increase in the cost of coal consumed from $53.88 per ton in 2025 to $55.05 per ton in 2026 and by $2.3 million of additional fuel oil consumed during start-ups associated with the equipment issues noted above. Fuel costs on a consolidated basis increased $1.8 million, or 3.1% to $59.2 million for the nine months ended September 30, 2026.

Other operating and maintenance costs increased $7.7 million, or 31.1%, from the first nine months of 2025. The increase was driven by $4.3 million of additional costs associated with the more significant scope of the planned major maintenance outage completed in 2026, a $1.8 million increase in property insurance premiums, and $1.9 million of higher consumable supplies, materials and maintenance services reflecting the equipment issues experienced at Merom. The impacted generating unit returned to service in July 2026.

Cost of purchased power increased $23.5 million, or 212.1%, versus the nine-month period ended September 30, 2025. When there is an outage at one of the generating units at Merom or energy hours at the Merom Hub are priced below our

production cost, we have the option to make economic net hourly purchases of power in the MISO market to satisfy our obligations, which we record as cost of purchased power. In 2026, we purchased an incremental 0.2 million MWh compared to 2025, an increase of 94.3% that was further impacted by the energy pricing dynamics at the time of the purchases.

Utilities expense increased $2.5 million, or 62.4%, compared to 2025, which was largely attributable to the frequency and timing of energy intensive start-ups of the generating units during the first half of 2026.

Labor expenses increased $2.8 million, or 11.9% in the nine-month period ended September 30, 2026 versus the comparable period in 2025 driven by the impact of incremental maintenance efforts associated with the planned major maintenance outage in combination with annual wage increases.

Other operating revenue decreased $2.9 million or 84.7% compared to the first nine months of 2025. This decrease primarily reflects the $3.0 million exclusivity agreement fee recognized in the second quarter of 2025.

Depreciation, depletion and amortization decreased $0.5 million, or 3.3%, compared to the first nine months of 2025, driven by a $4.8 million decrease resulting from the change in the estimated useful life of the Merom Station described above partially offset by capital additions placed in service.

Interest expense increased $3.3 million, or 53.0%, during the nine-month period ended September 30, 2026 versus the comparable period in 2025. The increase in our interest expense primarily relates to interest on the KLIM Facility ($2.7 million) and a $1.4 million increase in accretion on our prepaid delivered energy contracts entered into in 2024 and 2025. Hallador has not entered into any new prepaid delivered energy contracts in 2026.

Income before income taxes decreased $52.9 million from $49.1 million of income before taxes in the first nine months of 2025 to a loss before taxes of $3.9 million in the first nine months of 2026, which is attributable to the items described in the discussion above.

Coal Operations

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
	(in thousands)		(in thousands)	
Coal Sales	$ 50,631	$ 68,814	$ 147,917	$ 169,117
Fuel	$ (779)	$ (574)	$ (2,093)	$ (1,564)
Other Operating and Maintenance Costs	(24,482)	(35,046)	(67,582)	(77,147)
Utilities	(2,817)	(2,670)	(8,695)	(9,270)
Labor	(20,690)	(19,625)	(60,139)	(57,671)
General and Administrative	(2,397)	(2,062)	(6,826)	(6,290)
Segment EBITDA	(534)	8,837	2,582	17,175
Other Operating Revenue	696	1,582	2,624	4,206
Depreciation, Depletion and Amortization	(4,523)	(3,992)	(13,128)	(14,148)
ARO Accretion	(290)	(320)	(850)	(941)
Exploration Costs	(36)	(38)	(407)	(157)
(Loss) Gain on Disposal or Abandonment of Assets, Net	(343)	2,334	(157)	2,410
Interest Income	114	65	465	164
Interest Expense	(111)	(2,342)	(1,052)	(6,261)
Income (Loss) before Income Taxes	$ (5,027)	$ 6,126	$ (9,923)	$ 2,448

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2026	2025	2026	2025
	(in thousands) (per ton)		(in thousands) (per ton)	
Tons Sold (in thousands)	935	1,355	2,723	3,316
Coal Sales	$ 54.17	$ 50.79	$ 54.33	$ 51.00
Fuel	$ (0.83)	$ (0.42)	$ (0.77)	$ (0.47)
Other Operating and Maintenance Costs	(26.19)	(25.86)	(24.82)	(23.27)
Utilities	(3.01)	(1.97)	(3.19)	(2.80)
Labor	(22.14)	(14.48)	(22.09)	(17.39)
General and Administrative	(2.56)	(1.52)	(2.51)	(1.90)
Segment EBITDA	(0.56)	6.54	0.95	5.17
Other Operating Revenue	0.74	1.17	0.96	1.27
Depreciation, Depletion and Amortization	(4.84)	(2.95)	(4.82)	(4.27)
ARO Accretion	(0.31)	(0.24)	(0.31)	(0.28)
Exploration Costs	(0.04)	(0.03)	(0.15)	(0.05)
(Loss) Gain on Disposal or Abandonment of Assets, Net	(0.37)	1.72	(0.06)	0.73
Interest income	0.12	0.05	0.17	0.05
Interest expense	(0.12)	(1.73)	(0.39)	(1.89)
Loss on Extinguishment of Debt	—	—	—	—
Income (Loss) before Income Taxes	$ (5.38)	$ 4.53	$ (3.65)	$ 0.73

Q3 2026 vs. Q3 2025

Segment operating revenue from coal operations (including intercompany sales to Merom) decreased $18.2 million, or 26.4%, compared to the third quarter of 2025. The decrease was driven by lower volume partially offset by an increase in the average sales price for our coal. We sold 0.9 million tons of coal during the third quarter of 2026, a decrease of 0.4 million tons, or 31.0%, versus 2025. Our average sales price, on a segment basis, increased $3.38 per ton from $50.79 per ton to $54.17 per ton. Sunrise sold 16.9% fewer tons to Merom during the third quarter of 2026 compared to 2025, as Merom drew down its coal inventory, while tons sold to third parties decreased 0.4 million tons, or 35.8%. On a consolidated basis, third party sales decreased $15.1 million, or 29.5%, versus the third quarter of 2025, as the decrease in tons sold was partially offset by a 9.9% increase in our average third party price per ton from $50.79 in 2025 to $55.80 in 2026.

Other operating and maintenance costs decreased $10.6 million, or 30.1%, which is largely attributable to the 0.4 million, or 31.0%, reduction in tons sold, partially offset by higher mine expansion costs, versus the third quarter of 2025. Labor expenses increased $1.1 million, or 5.4%, from the third quarter of 2025 largely attributable to annual pay increases for our coal operations employees; however, because tons sold declined 31.0%, and labor costs are largely fixed, labor cost per ton sold rose $7.66 to $22.14 per ton.

Depreciation, Depletion and Amortization increased by $0.5 million, or 13.3%, compared to the third quarter of 2025, largely attributable to new and refurbished mining equipment placed in service over the past 12 months.

Interest expense decreased $2.2 million, or 95.3%, from $2.3 million for the three months ended September 30, 2025. The decrease is attributable to the paydown of the Company's prior bank facility in March 2026, while the new bank facility is not held within the Coal Operations segment.

Income before income taxes decreased by $11.2 million from income before income taxes of $6.1 million in the third quarter of 2025 to a loss before income taxes of $5.0 million in 2026. The main drivers of this change in income (loss) before income taxes are described in the discussion above.

YTD 2026 vs. YTD 2025

Segment operating revenue from coal operations (including intercompany sales to Merom) decreased $21.2 million, or 12.5%, compared to the nine months ended September 30, 2025. The decrease was driven by lower volume partially offset by an increase in the average sales price for our coal. We sold 2.7 million tons of coal during the first nine months of 2026, a decrease of 0.6 million tons, or 17.9%, versus 2025. Our average sales price, on a segment basis, increased $3.33 per ton from $51.00 per ton to $54.33 per ton. Sunrise sold 0.3 million fewer tons of coal to Merom due to the aforementioned equipment issues, while tons sold to third parties decreased 14.3%. On a consolidated basis, third party sales decreased $7.8 million, or 6.5%, versus the first nine months of 2025, as the decrease in tons sold was partially offset by a 9.1% increase in our average third party price per ton from $51.08 in 2025 to $55.72 in 2026.

Other operating and maintenance costs decreased $9.6 million, or 12.4%, which is largely attributable to the 0.6 million, or 17.9%, reduction in tons sold versus 2025, partially offset by higher mine expansion costs. Labor expenses increased $2.5 million, or 4.3%, from the nine months ended September 30, 2025; however, because tons sold declined 17.9%, and labor costs are largely fixed, labor cost per ton sold rose $4.70 to $22.09 per ton.

Depreciation, Depletion and Amortization decreased by $1.0 million, or 7.2%, compared to the first nine months of 2025.

Interest expense decreased $5.2 million, or 83.2%, from $6.3 million for the nine months ended September 30, 2025 to $1.1 million in 2026. The decrease is attributable to the paydown of the Company's prior bank facility in March 2026, while the new bank facility is not held within the Coal Operations segment.

Income (loss) before income taxes decreased by $12.4 million from income before income taxes of $2.4 million in the first nine months of 2025 to a loss before income taxes of $9.9 million in the nine-month period ended September 30, 2026. The main drivers of this change in income (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 2025	1st 2026	2nd 2026	3rd 2026	T4Qs
Tons produced	905	907	954	901	3,667
Tons sold	995	854	934	935	3,718
Wash plant recovery in %	57 %	59 %	63 %	62 %	
Capex (Coal Operations)	$ 6,449	$ 3,792	$ 4,038	$ 4,606	$ 18,885
Capex per ton sold (Coal Operations)	$ 6.48	$ 4.44	$ 4.32	$ 4.93	$ 5.08
Average cost per ton sold[1]	$ 46.75	$ 50.66	$ 49.77	$ 52.17	

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
Capex per ton sold (Coal Operations)	$ 12.66	$ 5.83	$ 6.51	$ 5.07	$ 7.16
Average cost per ton sold[1]	$ 43.25	$ 43.65	$ 46.03	$ 42.74	

[1] 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 divided by tons sold for the respective period in this table. Coal Operations costs are presented in the "Discussion and Analysis of our Reportable Segments" above.

EARNINGS (LOSS) PER SHARE

	4th 2025	1st 2026	2nd 2026	3rd 2026
Basic	$ (0.01)	$ (0.20)	$ (0.32)	$ (0.10)
Diluted	$ (0.01)	$ (0.20)	$ (0.32)	$ (0.10)

	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

INCOME TAXES

Our effective tax rate ("ETR") is estimated at ~0% for the nine months ended September 30, 2026 and 2025, respectively. Income tax expense of $1.8 million was recorded in the three months ended September 30, 2026, compared with a year-to-date income tax benefit of $1.7 million recorded through June 30, 2026. The change reflects a decrease in our estimated annual ETR. At June 30, 2026, we forecasted full-year pretax income, whereas at September 30, 2026, we forecast a full-year pretax loss, primarily due to financing costs related to the KLIM Facility, including the loss on extinguishment of the TCB Credit Facility and interest expense, and expected operating results. Our annual income tax estimate primarily reflects the change in our net deferred tax liability that is not offset by net operating loss carryforwards, which are limited to 80% of taxable income. For the nine months ended September 30, 2026, 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 the valuation allowance and, historically, statutory 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.

RESTRICTED STOCK GRANTS

See *"Item 1. Financial Statements - Note 9 - Stock Compensation Plans"* for a discussion of restricted stock unit ("RSUs").

MATERIAL CHANGES IN FINANCIAL CONDITION

Sources and Uses of Cash

We are a holding company that is dependent on the capital resources of our subsidiaries to satisfy our liquidity requirements at the corporate level. Each of our significant operating subsidiaries typically generate cash from operating activities, but our ability to access the liquidity of these and other subsidiaries may be limited by tax and legal considerations, and other factors.

Cash and cash equivalents

Hallador had $433.0 million of cash and restricted cash as of September 30, 2026 versus $15.4 million at December 31, 2025.

Liquidity of Hallador

Our short-term sources of corporate liquidity include (i) cash and cash equivalents held by Hallador, (ii) cash provided by operations, (iii) interest income received on our cash and cash equivalents. For the details of the borrowing capacity under our credit facility, see *"Item 1. Financial Statements - Note 5 – Debt"* to our unaudited condensed consolidated financial statements.

The liquidity of Hallador generally is used to fund (i) capital expenditures, (ii) debt service requirements and (iii) general and administrative expenses, as well as to settle certain obligations that are not included on our September 30, 2026 unaudited condensed consolidated balance sheet. In this regard, we have commitments and contingent obligations related to (a) the acquisition of equipment under the APA, (b) leases of railcars that qualify for the short-term lease exception (c) certain operating costs associated with our Electric Operations and our Coal Operations, and (d) the MOIC Premium that would be payable upon repayment of the KLIM Facility, as described under "Capitalization" below.

From time to time, we may also require liquidity in connection with (i) acquisitions and other investment opportunities, (ii) the satisfaction of contingent liabilities, (iii) capital distributions to Hallador equity owners, (iv) the repayment of third-party debt, or (v) income tax payments. No assurance can be given that any external funding would be available to us on acceptable terms, or at all.

Liquidity consists of our additional borrowing capacity and unrestricted cash and cash equivalents. As of September 30, 2026, we did not have additional borrowing capacity under the KLIM Facility and total liquidity of $103.2 million. Our liquidity is net of $19.7 million in outstanding letters of credit that were cash collateralized as of September 30, 2026 to maintain surety bonds and other credit support obligations.

Turbine Equipment Acquisition

As of September 30, 2026, we had paid $23.8 million of the purchase price under the APA in the form of payments to third party vendors made on behalf of the Seller and had a remaining balance of the purchase price of approximately $326.2 million. In October 2026, we paid $326.0 million of the remaining balance, including the third and fourth installments under the APA of $315.0 million ($50.0 million to the Seller and $265.0 million into an escrow account held by the Seller, to which we do not have access), and title to the equipment transferred to us. As of October 31, 2026, we had paid $349.8 million of the $350.0 million purchase price, with approximately $0.2 million remaining payable to third party vendors on behalf of the Seller, which will be paid in accordance with the APA. The escrowed amount is not available to fund our other cash requirements. The approximately $100.0 million of expected transportation, refurbishment, insurance, and logistics costs, together with the remaining costs of the Turtle Creek Project, represents a material cash requirement. We expect to fund these costs with cash on hand, cash from operations, and the delayed draw term loan commitment under the KLIM Facility, which is available only to fund the Turtle Creek Project, subject to funding conditions. The Turtle Creek Project may also require incremental external funding. No assurance can be given that any external funding would be available to us on acceptable terms, or at all.

Consolidated Statement of Cash Flows Summary.

The unaudited condensed consolidated statements of cash flows are summarized as follows for the periods presented:

	Nine Months Ended September 30,		
	2026	2025	Change
	(in millions)		
Net cash provided by (used in) operating activities	$ (25.1)	$ 73.0	$ (98.1)
Net cash used in investing activities	(90.9)	(41.8)	(49.1)
Net cash provided by (used in) financing activities	533.6	(7.9)	541.5
Increase in cash, cash equivalents, and restricted cash	$ 417.6	$ 23.3	$ 394.3

Operating Activities. The decrease in net cash provided by our operating activities is primarily attributable to the combination of (i) lower Adjusted EBITDA and related working capital items, (ii) lower cash receipts from prepaid forward sales contracts, partially offset by incremental cash received for annual sales of accredited capacity compared to 2025 and lower cash payments of interest. Consolidated Adjusted EBITDA is a measure that is not calculated in accordance with U.S. generally accepted accounting principles ("GAAP"), which investors should view as a supplement to, and not a substitute for, GAAP measures of performance included in our condensed consolidated statements of operations.

Investing Activities. The change in net cash used by our investing activities is primarily attributable to (i) an increase in our capital expenditures of $46.8 million attributable to incremental capital expenditure projects of $13.7 million at Merom and an incremental $39.5 million related to the Turtle Creek Project, of which $23.8 million related to payments under the APA, (see *"Note 15 – Commitments and Contingencies"*) to the condensed consolidated financial statements, partially offset by lower capitalization of mine development costs at Oaktown and (ii) a $0.4 million decrease in investments in equity method affiliates.

For the nine months ended September 30, 2026, capital expenditures ("Capex") was $91.1 million allocated as follows (in millions):

Oaktown	$	12.4
Merom and other power projects		31.7
Merom - ELG		7.4
Turtle Creek Project		39.5
Capex per the condensed consolidated statements of cash flows	$	91.1

We expect our 2026 Capex to modestly increase as compared to our 2025 Capex, excluding any impacts of the Turtle Creek Project. The actual amount of our 2026 Capex may vary from our expectations for a variety of reasons, including (i) changes in (a) the competitive or regulatory environment, (b) business plans, or (c) our expected future operating results and (ii) the availability of sufficient capital. Accordingly, no assurance can be given that our actual Capex will not vary materially from our expectations.

Financing Activities. The increase in net cash provided by our financing activities is primarily attributable to the net effect of (i) an increase in net borrowings of debt of $520.0 million largely attributable to the KLIM Facility, (ii) an increase in cash of $53.8 million from the net proceeds of the January 2026 CMPO, (iii) incremental payments of debt issuance costs of $32.1 million, and (iv) a decrease in cash from incremental lease financing payments of $1.3 million.

Capitalization

We seek to maintain our debt at levels that provide for equity returns without assuming undue risk. Our ability to service or refinance our debt and to maintain compliance with the leverage covenants in our credit agreement is dependent primarily on our ability to maintain or increase the Adjusted EBITDA of our consolidated businesses, maintain adequate liquidity and coverage of fixed charges, and to achieve adequate returns on our capital expenditures and acquisitions.

Consolidated Adjusted EBITDA is a non-GAAP measure, which investors should view as a supplement to, and not a substitute for, GAAP measures of performance included in our condensed consolidated statements of operations. In addition, our ability to access the delayed draw term loan commitment under the KLIM facility is subject to conditions precedent including satisfactory commercialization and execution of a construction agreement. Further, we anticipate that if we are able to enter into a Super Priority Revolver as permitted under the KLIM facility that there would be standard market terms and conditions related to the availability of funds. For example, if the Adjusted EBITDA of our business was to decline, our ability to obtain additional debt could be limited.

Prior to March 5, 2026, the Company was party to a credit agreement with PNC Bank, National Association (in its capacity as administrative agent, "PNC Bank"). As of December 31, 2025, our debt under the PNC Bank credit facility was $30.0 million, which was repaid subsequent to year-end as further described below.

On March 5, 2026, Hallador entered into a credit agreement with Texas Capital Bank and Old National Bank, among others, that replaced the credit agreement with PNC Bank and included a $75.0 million revolving credit facility (the "TCB Revolving Credit Facility") and a $45.0 million delayed draw term loan (the "TCB Delayed Draw Term Loan", and together with the TCB Revolving Credit Facility, the "TCB Credit Facility"). The TCB Credit Facility was used to repay the PNC Bank credit facility and for working capital and general corporate purposes. The TCB Credit Facility was repaid in full and terminated on September 15, 2026 with proceeds of the KLIM Facility.

On September 15, 2026, Hallador Energy Company and its wholly-owned subsidiary, Turtle Creek Gas Holdings, LLC ("Turtle Creek"), each as a co-borrower, jointly and severally liable for all obligations thereunder, entered into a Credit Agreement (the "Credit Agreement") with Kennedy Lewis Investment Management LLC ("KLIM"), acting for certain managed or advised funds and accounts, the other lenders from time to time party thereto, U.S. Bank Trust Company, National Association, as administrative agent, and U.S. Bank National Association, as collateral agent. The Credit Agreement provides for a $600.0 million senior secured term loan facility, with $550.0 million funded at closing and a $50.0 million delayed draw available for 12 months after closing, subject to an agreed draw schedule and funding conditions (the "KLIM Facility"). The KLIM Facility was entered into to repay the TCB Credit Facility and to finance the development and construction of the Turtle Creek Project. See "*Note 5 — Debt*" to the condensed consolidated financial statements for additional information.

MOIC Premium. Upon repayment in full of the KLIM term loans, whether at maturity, upon acceleration, or in connection with a refinancing or other prepayment, we are required to pay a premium to the extent necessary for each lender to have received total payments and outstanding principal (including PIK interest) equal to at least 1.35 times its funded term commitment, increasing to 1.5 times if the maturity date is extended (the "MOIC Premium"). The MOIC Premium declines as interest is paid or accrues over time, and is largest if the term loans are repaid early. For illustrative purposes, if the term loans had been repaid in full on September 30, 2026, we would have been required to pay a MOIC Premium of approximately $190.6 million. The MOIC Premium is not recorded as a liability as of September 30, 2026. See "Note 5 – Debt." We may pursue a refinancing of the KLIM Facility prior to its scheduled maturity, which would require payment of any MOIC Premium then due. Any such payment could be significant and would require us to use available cash or obtain additional financing, which may not be available on acceptable terms or at all.

See "*Item 1. Financial Statements - Note 5 – Debt*" to our unaudited condensed consolidated financial statements for additional discussion about our debt and related liquidity.

Off-Balance Sheet Arrangements

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 $18.6 million, including $6.6 million at Merom, presented as asset retirement obligations ("ARO") 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.

CRITICAL ACCOUNTING ESTIMATES

For a description of our critical accounting policies and estimates, refer to "*Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations*" included in our 2025 Form 10-K. We did not have any material changes in critical accounting policies, estimates, judgments and assumptions during the three and nine months ended September 30, 2026.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to several market risks in the Company's normal business activities. Market risk is the potential loss that may result from market changes associated with the Company's power generation and mining activities, or with existing or forecasted financial or commodity transactions. The types of market risks that Hallador is exposed to are commodity price risk, interest rate risk, inflation risk, and counterparty credit risk.

Commodity Price Risk

Commodity price risks result from exposures to changes in spot prices, forward prices, volatilities, and correlations between various commodities, such as natural gas, electricity, coal, oil, and emissions credits. We manage the commodity price risk of the Company's generation and mining operations by entering into various instruments to manage the variability in future cash flows from forecasted sales and purchases of power and fuel. These instruments include prepaid forward contracts, PPAs, and other bilateral agreements. Hallador uses these agreements to manage and fix the prices of certain purchases and sales to alleviate market risk and improve visibility into future results. See the *"Forward Sales Position"* table within the *"Material Changes in Results of Operations"* section of *"Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations"*.

We are exposed to market price fluctuations for emission credits related to our investments in Sunrise Energy and Oaktown Gas, which had an aggregate carrying value of $2.6 million at September 30, 2026. For additional information regarding our investments in Sunrise Energy and Oaktown Gas, see *"Item 1. Financial Statements - Note 12. – Equity Method Investments"* to our condensed consolidated financial statements.

Interest Rate Risk

We are exposed to changes in interest rates primarily as a result of our borrowing activities, which include instruments with variable rates. Our primary exposure to variable rates is through our SOFR-indexed credit facilities.

In general, we monitor the interest rate market and determine whether to enter into instruments to protect against increases in the interest rates on our variable-rate debt. From time to time, we may use interest rate swaps, interest rate cap, floor or collar agreements that lock in a maximum interest rate if variable rates rise, but also may allow our company to benefit, to a limited extent in the case of collars, from declines in market rates. We use judgment to determine the appropriate composition of interest rate derivative instruments, taking into account the relative costs and benefits in light of current and expected future market conditions, liquidity issues and other factors. As of September 30, 2026 and December 31, 2025, we did not hold any interest rate derivative instruments.

Weighted Average Variable Interest Rate. At September 30, 2026 and December 31, 2025, the outstanding principal amount of our variable-rate indebtedness aggregated $551.9 million and $30.0 million, respectively, and the weighted average interest rate (including margin) on such variable-rate indebtedness was approximately 11.89% and 8.17%, respectively, excluding the effects of interest rate derivative contracts, deferred financing costs, original issue premiums or discounts and commitment fees, all of which affect our overall cost of borrowing. A 100 basis point increase in SOFR would increase annual interest expense by approximately $5.5 million.

Inflation Risk

We are subject to inflationary pressures with respect to labor, procurement of electrical and mining equipment, and other costs. While we attempt to increase our revenue to offset increases in costs, there is no assurance that we will be able to do so. Therefore, costs could rise faster than associated revenue, thereby resulting in a negative impact on our operating results, cash flows and liquidity. The economic environment in which we operate is a function of government, economic, fiscal and monetary policies and various other factors beyond our control that could lead to inflation. We are unable to predict the extent that price levels might be impacted in future periods in the markets in which we operate.

Counterparty Credit Risk

We are exposed to the risk that the counterparties to our undrawn debt facilities and cash investments will default on their obligations to us. We manage these credit risks through the evaluation and monitoring of the creditworthiness of, and concentration of risk with, the respective counterparties. In this regard, the default of KLIM could have a significant impact on our business. Most of our cash currently is invested in either (i) money market funds, including funds that invest in high-quality short-term instruments that preserve principal and offer daily liquidity, or (ii) overnight deposits with banks that transfer balances nightly into repurchase agreements collateralized by high-quality securities, including US

government instruments. To date, neither the access to nor the value of our cash and cash equivalent balances have been adversely impacted by liquidity problems of financial institutions.

We are also exposed to counterparty performance risk under the APA. Our ability to receive the turbine equipment we agreed to purchase, and to recover amounts we paid toward the purchase price, depends on the performance of the Seller and its designated vendors.

We invest our cash with financial institutions that meet high credit quality standards. We are exposed to the credit risk of these financial institutions and to interest rate risk in relation to the interest earning potential of our cash and cash equivalent balances. In order to mitigate these risks, we actively manage the deposits of our cash balances in light of our and our subsidiaries' forecasted liquidity requirements.

At September 30, 2026 and December 31, 2025, our exposure to counterparty credit risk included (i) cash and cash equivalents and restricted cash of $433.0 million and $15.4 million, respectively, and (ii) aggregate availability of undrawn debt facilities of $0.0 million and $28.8 million, respectively (excluding, as of September 30, 2026, the $50.0 million delayed draw term loan commitment under the KLIM Facility, which is available only to fund the Turtle Creek Project).

While we currently have no specific concerns about the creditworthiness of any counterparty for which we have material credit risk exposures, we cannot rule out the possibility that one or more of our counterparties could fail or otherwise be unable to meet its obligations to us. Any such instance could have an adverse effect on our cash flows, results of operations, financial condition and/or liquidity.

Although we actively monitor the creditworthiness of our key vendors, the financial failure of a key vendor could disrupt our operations and have an adverse impact on our revenue and cash flows.

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 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 upon that evaluation, our CEO and CFO concluded that our disclosure controls and procedures are effective for the purposes discussed above.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There have been no changes to our internal control over financial reporting during the quarter ended September 30, 2026, that materially affected or are reasonably likely to materially affect our internal control over financial reporting.

PART II - OTHER INFORMATION
ITEM 1. LEGAL PROCEEDINGS

See *Item 1. Financial Statements - Note 15. – "Commitments and Contingencies"* to our condensed consolidated financial statements. Except as described therein, the Company is not currently a party to any legal proceedings that management believes, either individually or in the aggregate, would reasonably be expected to have a material adverse effect on the Company's business, results of operations, financial condition, or liquidity.

ITEM 1A. RISK FACTORS

There have been no material changes to the risk factors disclosed in Part I, Item 1A, "Risk Factors" in our Annual Report on Form 10-K for the fiscal year ended December 31, 2025, filed with the SEC on March 12, 2026, except as set forth below. Certain of the risk factors set forth below supplement and update the corresponding risk factors included in Part II, Item 1A of our Quarterly Report on Form 10-Q for the quarter ended June 30, 2026 and, therefore, supersede such risk factors.

We have made substantial payments to acquire turbine equipment and will require significant additional capital to transport, refurbish, and deploy it and to complete the Turtle Creek Project, and our failure to obtain that capital or to perform our obligations under the related agreements could have a material adverse effect on our business, financial condition, and results of operations.

On May 30, 2026, we entered into an Asset Purchase Agreement (the "APA") with Energy World Corporation Ltd. (the "Seller") to acquire approximately 460 MW of Siemens gas turbines, generators, a steam turbine, and ancillary equipment for a total purchase price of $350.0 million, plus approximately $100.0 million of additional costs we expect to incur for transportation, refurbishment, insurance, and logistics. As of September 30, 2026, we have paid $23.8 million of the purchase price, and we paid an additional $326.0 million from October 1 through October 31, 2026 in accordance with the APA. The remaining balance of approximately $0.2 million is expected to become payable in the fourth quarter of 2026.

Although we have paid substantially all of the purchase price with proceeds of the KLIM Facility, we expect to incur approximately $100.0 million of additional costs for transportation, refurbishment, insurance, and logistics, together with significant additional costs to complete the Turtle Creek Project. The amounts available to us for these purposes, including the $50.0 million delayed draw term loan commitment under the KLIM Facility (which is subject to funding conditions and may be used only to fund the Turtle Creek Project), may not be sufficient to fund these costs. We estimate the total costs of the Turtle Creek Project to be less than $800.0 million. Following the expenditures to date, including the October 2026 payments made in connection with the APA, we still have significant capital requirements to complete the project including: refurbishment, engineering, construction, transportation, insurance, logistics, and other costs. We have not secured commitments for any additional financing, and there can be no assurance that additional financing will be available to us on acceptable terms, or at all, particularly in light of the restrictions on additional indebtedness and liens in the KLIM Credit Agreement. If we are unable to obtain sufficient financing on a timely basis, we may be unable to complete the Turtle Creek Project by the date required under the KLIM Credit Agreement, the failure of which would constitute an event of default, and we may be required to delay, scale back, or abandon the project, any of which could have a material adverse effect on our business, financial condition, cash flows, and results of operations.

The turbine equipment we are acquiring is intended to support our proposed expansion of generation capacity through MISO's ERAS program. Our ability to complete that expansion and to realize the anticipated benefits of the equipment is subject to execution of a generator interconnection agreement and other construction, permitting, financing, and regulatory contingencies, many of which are outside our control and have not yet been satisfied. If we do not obtain the necessary approvals, or if the expansion project does not otherwise proceed, we may be unable to deploy the equipment as planned, and our alternatives may be limited to selling the project together with the equipment or selling the equipment on a standalone basis, potentially at a loss and on terms less favorable than we currently anticipate. Any such sale could require a mandatory prepayment of the KLIM Facility, and any repayment of the KLIM Facility in full would require payment of the MOIC Premium.

The turbine equipment must be transported internationally and domestically through a complex, multi-stage logistics process, and delays, damage, or cost overruns in that process could adversely affect the cost, timing, and expected benefits of our planned expansion.

The turbine equipment we are acquiring under the APA is currently located outside the United States and must be transported through a complex, multi-stage logistics process before it can be placed into service, including the remainder of its ocean shipment to the United States, customs and import clearance, and overland transport to a Siemens facility for inspection and refurbishment, followed by transport to the site of our planned expansion at our Merom Station in Sullivan County, Indiana. The equipment consists of large, heavy, and specialized components that require heavy-lift vessels, specialized rigging and transport equipment, and oversize and overweight load permits, and we will rely on the Seller, its designated vendors, Siemens, and other third-party carriers and logistics providers, whose performance is largely outside our control.

This process is subject to numerous risks, including damage to or loss of the equipment in transit; limited availability of qualified vessels, carriers, and equipment; port congestion and labor disruptions; adverse weather; delays in obtaining export licenses, import clearances, and transport permits; geopolitical events and disruptions to shipping lanes; and the imposition of, or changes in, tariffs, duties, and other trade measures applicable to imports into the United States. The equipment includes long-lead-time components that would be difficult, time-consuming, and costly to repair or replace if damaged or lost in transit. Any insurance we maintain on the equipment during transport may not be sufficient to cover all losses and would not compensate us for delays to our planned expansion.

Our estimate of approximately $100.0 million of transportation, refurbishment, insurance, and logistics costs is based on assumptions regarding, among other things, shipping costs, carrier and equipment availability, tariff and duty rates, permitting timelines, and the scope of refurbishment work required, any of which may prove inaccurate, and actual costs could materially exceed that estimate, increasing the amount of financing we require. In addition, because we have paid substantially all of the purchase price and bear the risk of loss of the equipment in transit, delays or losses in the logistics process could increase our costs and affect our financing plans without any corresponding reduction in our payment obligations. Any material delay, damage, or cost overrun could delay our planned expansion, jeopardize milestones associated with MISO's ERAS program, increase project costs, and impair our ability to realize the anticipated benefits of the equipment, any of which could have a material adverse effect on our business, financial condition, cash flows, and results of operations.

Our indebtedness under the KLIM Facility is substantial and costly, is secured by substantially all of our assets, and contains restrictive covenants, and a failure to comply with its terms or to repay it when due could have a material adverse effect on our business and financial condition.

On September 15, 2026, we and Turtle Creek incurred $550.0 million of term loans under the KLIM Facility, and a further $50.0 million is available under the delayed draw term loan commitment solely to fund the Turtle Creek Project. The KLIM Facility bears a substantially higher interest rate than our prior credit facilities, a portion of which accrues as paid-in-kind ("PIK") interest that increases the principal amount we must repay, and, upon repayment, requires payment of a premium (the MOIC Premium) sufficient for the lenders to receive at least 1.35 times their funded term commitment (1.50 times if the maturity date is extended). The Closing Date Intercompany Loan was not repaid by October 31, 2026, and as a result the PIK interest rate has increased; it will increase further if the loan remains outstanding after January 15, 2027. We and Turtle Creek are jointly and severally liable for the KLIM Facility, which is secured by first-priority liens on substantially all of our assets, including the Merom Station and certain mining assets. Beginning with the test period ending December 31, 2026, we must maintain unrestricted cash of at least $10.0 million, which is not subject to a cure right, and a minimum debt service coverage ratio, and following the Commercial Operation Date we must also comply with maximum leverage ratios. The KLIM Facility also restricts the transfer of cash from Turtle Creek and its subsidiaries to us, requires mandatory prepayments from excess cash flow and certain asset sales, contains cross-default provisions, and provides that it is an event of default if the Commercial Operation Date has not occurred on or before June 30, 2029. The KLIM Facility matures on September 15, 2029 unless extended with lender consent and payment of an extension fee, and we may not be able to refinance it on acceptable terms, or at all. A default could permit the lenders to accelerate the obligations, require payment of the MOIC Premium, and foreclose on our collateral, including Merom, which would materially and adversely affect our business, financial condition, and results of operations.

We may be unable to complete the Turtle Creek Project on time, within our budget, or at all.

The Turtle Creek Project requires, among other things, execution of a generator interconnection agreement, engineering and construction contracts, interconnection, air and other permits, and natural gas supply and transportation arrangements, some of which have not been obtained or finalized, and the performance of contractors, equipment suppliers, and other counterparties. We expect the project to reach commercial operation in the second half of 2028, but delays, cost overruns, or other events could prevent us from achieving the Commercial Operation Date by June 30, 2029, which would constitute an event of default under the KLIM Credit Agreement. We may be required to obtain additional financing to complete the project. Failure to complete the project, or to complete it on the anticipated timeline and budget, could materially and adversely affect our business, financial condition, and results of operations.

Our contracted forward sales position includes agreements that are unit contingent or subject to customer volume options, and the revenue we expect to realize from them may differ materially from our estimates.

The Energy PPA is unit contingent, so that base quantities are reduced if one or both Merom Station generating units are not producing energy above a certain threshold, and it permits the Indiana Utility to reduce the base energy quantity to zero for up to 90 days per year. Our estimates of energy quantities and revenue under the Energy PPA are based on forward energy curve pricing and management's assumptions regarding Merom Station's availability, which was adversely affected in 2026 by equipment issues and unplanned outages. As a result, the revenue we ultimately realize from our forward sales position could be materially lower than the amounts presented in the Forward Sales Position table.

Merom Station has experienced significant outages in 2026, and its estimated useful life through 2040 may not prove accurate.

During 2026, Merom Station experienced equipment issues, a planned major maintenance outage, and unplanned outages that reduced generation and increased the cost of purchased power, maintenance, and fuel oil. We extended the estimated useful life of Merom Station through 2040 as a change in accounting estimate effective June 1, 2026, which reduced depreciation expense. If Merom Station is unable to operate economically through 2040, including as a result of its age, environmental compliance costs, market conditions, or regulatory changes, we could be required to shorten its estimated useful life or record impairment charges, which could materially and adversely affect our results of operations.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

During the nine months ended September 30, 2026, all sales and issuances of the Company's equity securities were registered under the Securities Act of 1933, as amended. Accordingly, during the period covered by this report, the Company did not engage in any unregistered sales of its equity securities that would be required to be disclosed pursuant to Item 701 of Regulation S-K. For a description of the Company's registered equity issuances during the year, including shares issued under the ATM Program and the CMPO, see *Item 1. Financial Statements - Note 16 – "At Market Agreement ("ATM") and Confidentially Marketed Public Offering ("CMPO")"* to our condensed consolidated financial statements.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

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

ITEM 5. OTHER INFORMATION

Rule 10b5-1 Trading Arrangements

During the three months ended September 30, 2026, no director or officer of the Company adopted, modified, or terminated a Rule 10b5-1 trading arrangement or a non-Rule 10b5-1 trading arrangement as defined in Item 408 of Regulation S-K.

ITEM 6. EXHIBITS

Exhibit No.	Document
10.1	Credit Agreement Dated as of September 15, 2026 by and among Hallador Energy Company and Turtle Creek Gas Holdings, LLC and US Bank Trust Company, National Association, as Administrative Agent *
31.1	SOX 302 Certification - Chief Executive Officer*
31.2	SOX 302 Certification - Chief Financial Officer*
31.3	SOX 302 Certification – Chief Accounting Officer*
32	SOX 906 Certification*
95.1	Mine Safety Disclosure*
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)*

* Filed herewith.

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 9, 2026 /s/BRENT K. BILSLAND
Brent K. Bilsland, Chairman, President and CEO

Date: November 9, 2026 /s/TODD E. TELESZ
Todd E. Telesz, CFO

Date: November 9, 2026 /s/ERIC VAN DEMAN
Eric Van Deman, CAO