During the third quarter of 2025 and subsequently, Rubellite positively advanced its 2025 strategic priorities which include:

1. Optimize Development of Base Assets for Heavy Oil Growth;
2. Drive Top Quartile Capital Efficiencies;
3. Advance Enhanced Oil Recovery on Core Assets;
4. De-risk Exploration Prospects and Expand Portfolio;
5. Grow Land Base and Prospect Inventory for Chosen Play Strategies;
6. Increase Reserve-Based Net Asset Value and Potential Asset Value per Share;
7. Re-Establish Pristine Balance Sheet and Manage Risk; and
8. Drive Operational Excellence and Capture Cost Efficiencies.

THIRD QUARTER 2025 HIGHLIGHTS

Sales Production Volumes

- Conventional heavy oil sales production averaged 8,338 bbl/d, a 40% increase from the third quarter of 2024 (Q3 2024 - 5,954 bbl/d).

- Total sales production averaged 12,122 boe/d (71% heavy oil and natural gas liquids ("NGL")), a 104% increase from the third quarter of 2024 (Q3 2024 - 5,954 boe/d (100% heavy oil)).

- Rubellite brought 11 gross (9.0 net) heavy oil wells on production at Figure Lake and Frog Lake during the quarter.

- The Company's West Central 2025 drilling program commenced in July, adding 2 gross (1.0 net) liquids-rich conventional natural gas wells at East Edson to sales production late in the third quarter.

- Natural gas sales through the Figure Lake gas plant, operational since January 23, 2025, averaged 2.9 MMcf/d and 4 bbl/d of associated NGL.

Capital Expenditures

- Exploration and development capital expenditures(1) totaled $33.7 million to drill, complete, equip and tie-in 5 gross (5.0 net) multi-lateral horizontal development wells at Figure Lake, 7 gross (5.5 net) multi-lateral horizontal development wells at Frog Lake and 2 gross (1.0 net) liquids-rich conventional natural gas wells at East Edson.

- Exploration and development spending in the third quarter included $1.5 million to expand the Figure Lake gas plant and gas gathering system, increasing capacity from 3.0 MMcf/d to 6.4 MMcf/d.

- Land and other spending totaled $1.5 million and included $0.2 million for seismic purchases (Q3 2024 - $2.9 million). In addition to land purchases during the quarter, the Company sold undeveloped land for proceeds of $5.5 million which served to fund other capital activities and reduce net debt. Subsequent to the end of the third quarter, Rubellite closed the sale of additional undeveloped land for $2.3 million.

- Decommissioning, abandonment and reclamation spending totalled $0.4 million during the third quarter of 2025 (Q3 2024 - $0.2 million).

Financial Performance

- Adjusted funds flow(1) was $35.7 million ($0.38 per share), up 55% (9% per share) from the third quarter of 2024 (Q3 2024 - $23.0 million or $0.35 per share).

- Cash costs(1) were $18.6 million or $16.66/boe, down 33% on a per boe basis from the third quarter of 2024 (Q3 2024 - $13.5 million or $24.72/boe).

- Net income for the quarter was $5.6 million ($0.06 per share) compared to $15.0 million net income ($0.23 per share) in the third quarter of 2024.

Balance Sheet and Liquidity

- As at September 30, 2025, net debt(1) was $138.4 million, a 10% reduction from $154.0 million as at December 31, 2024, driven by $17.4 million of positive free funds flow(1) during the first nine months of 2025 combined with $5.5 million of proceeds from the sale of undeveloped land which was used to reduce net debt and other balance sheet obligations.

- Rubellite had available liquidity(2) at September 30, 2025 of $48.0 million, comprised of the $140.0 million borrowing limit of Rubellite's first lien credit facility, less current bank borrowings of $90.6 million and outstanding letters of credit of $1.4 million.

(1) Non-GAAP financial measure, non-GAAP ratio or supplementary financial measure. See "Non-GAAP and Other Financial Measures" in this interim report.
(2) See "Liquidity, Capitalization and Financial Resources - Capital Management" in the Q3 2025 MD&A.

OPERATIONS UPDATE

Greater Figure Lake (Figure Lake and Edwand)

Heavy oil sales production from the Greater Figure Lake area averaged 5,110 bbl/d for the third quarter (Q2 2025 - 5,544 bbl/d). Additionally, gas sales contributed 2.9 MMcf/d plus associated natural gas liquids of 4 bbl/d which brought total sales production at Figure Lake for the third quarter to 5,601 boe/d (91% oil and liquids) (Q2 2025 - 6,064 bbl/d; 92% oil and liquids). Rubellite completed the expansion of the Figure Lake 1-13 Gas Plant to manage additional associated gas volumes in late August, establishing total throughput capacity of approximately 6.4 MMcf/d.

During the third quarter of 2025, Rubellite drilled and rig released 4 gross (4.0 net) development horizontal wells from the 9-35-63-18W4 pad (the "9-35 Pad"), all targeting the Wabiskaw Member of the Clearwater Formation, with 33 meter inter-leg spacing and 15,000m open hole length per the Figure Lake well design adopted in the latter half of 2024. Results from the 2025 development capital program to date across the Greater Figure Lake field continue to outperform expectations, with an average[1] IP30 of 259 bbl/d (9 wells) and IP60 of 239 bbl/d (8 wells), as compared to the McDaniel Tier 1 Type Curve[2] rates for 33 meter inter-leg spacing of 177 bbl/d (IP30) and 169 bbl/d[2] (IP60).

In addition to development drilling in the third quarter, 1 gross (1.0 net) step-out delineation well was drilled in the Edwand region with 50m inter-leg spacing and ~10,000m open hole length, to test and confirm productivity from a new pool in the Wabiskaw Member. The step-out well achieved an IP30 and IP60 of 48 bbl/d and 36 bbl/d, respectively.

Development drilling is continuing through the fourth quarter from the 9-35 Pad, including one waterflood pilot pattern consisting of a single horizontal multi-lateral well with two sets of four legs each (8 legs in total), with ~165 meters between the four-leg sets. Each 4-leg set will be drilled with 33 meter inter-leg spacing, and the waterflood producer well will have a planned total open hole length for the 8 legs of approximately 8,500 meters. A separate single leg water injection well will be drilled along the center line between the two 4-leg sets, and water injection is expected to commence in early 2026.

The Company advanced its novel natural gas-based re-injection pilot at Figure Lake for enhanced oil recovery, with an experimental well now configured at the 01-13-063-18W4 pad (the "1-13 Pad"), on the same site as the Figure Lake 1-13 Gas Plant. A total of ~25 MMcf of natural gas was injected into an existing open-hole multi-lateral well in order to confirm injectivity. Natural gas is being flowed back at controlled rates in advance of a second injection test, after which the well will be reconfigured for heavy oil production. Results from the waterflood pilot and natural gas-based re-injection experiment will inform future development patterns and enhanced oil recovery techniques to be implemented across the Greater Figure Lake area.

Rubellite also commenced testing larger diameter (200mm) boreholes at the 9-35 Pad to determine if incremental economic returns associated with improved inflow and productivity can be realized relative to the robust economics established for the existing 159mm boreholes drilled to date at Figure Lake. A total of 3 gross (3.0 net) wells with the 200mm borehole diameter will be drilled by year end.

A Sparky exploration well at Figure Lake is planned for the fourth quarter of 2025. If successful, there are approximately 15.0 net follow-up Sparky locations which would be incremental to the existing Clearwater development inventory.

During the third quarter, the Company was successful in acquiring 4.0 net sections of land. With the additional acreage, and adjusted to reflect both 2025 step-out and development drilling activity, Rubellite has an inventory of 260.2 net development locations[3] identified in the Wabiskaw, including 88.2 net proven and probable undeveloped[2][3] booked locations. Under a one-rig program, which would provide for the drilling of 18 wells per year at Figure Lake, the Clearwater location count at Figure Lake represents ~14 years of low-risk development drilling inventory.

Frog Lake

Production at the Frog Lake property averaged 2,697 bbl/d (100% heavy oil) for the third quarter of 2025, a 6% increase from the second quarter of 2025 (Q2 2025 2,539 bbl/d).

During the third quarter, 1 gross (1.0 net) Waseca North well, 4 gross (3.0 net) Waseca South wells, and 2 gross (1.5 net) exploratory General Petroleum ("GP") wells were drilled, for a total of 7 gross (5.5 net) wells.

Rubellite switched its drilling operations at Frog Lake in December 2024 to utilize OBM. The OBM trial at Frog Lake has confirmed the benefits of using OBM fluid consistent with Rubellite's operations at Figure Lake, where the use of OBM has modestly reduced the cost of the mud system net of recovered OBM suitable for re-use and the sales credit for OBM that is not fit for re-use. Additional benefits include improved hole cleaning and stability, accelerated time to stabilized reservoir production, reduced drill pipe wear, and reduced water handling and disposal costs as compared to conventional water-based mud systems. The Company is continuing to utilize OBM in its ongoing drilling operations at Frog Lake as it evaluates the effects on long term production performance in different formations across the Frog Lake field.

Results thus far from the 2025 capital drilling program targeting the Waseca North sand at Frog Lake (13 gross (9.5 net) wells) have achieved an average[1] IP30 and IP60 of 133 bbl/d (13 wells) and 113 bbl/d (13 wells) respectively, as compared to the McDaniel Waseca North Type Curve[2] IP30 and IP60 of 107 bbl/d and 104 bbl/d established by McDaniel at year-end 2024 using historical data obtained from wells drilled with water-based mud systems.

2 gross (2.0 net) of the 4 gross (3.0 net) South Waseca sand wells drilled in the third quarter, have achieved an average IP30 of 159 bbl/d as compared to the McDaniel South Type Curve[2] of 150 bbl/d, while the remaining wells are either still recovering load fluid or are within the 30 day initial production period.

In addition to continued drilling of the Waseca sand as the primary development zone at Frog Lake, the Company drilled 2 gross (1.5 net) exploratory wells in the third quarter of 2025, targeting the GP sand. One gross (0.5 net) was drilled using a single leg lined horizontal lateral design and one gross (1.0 net) was drilled with a lined "fish bone" design. Both wells were equipped with recycle strings to aid in the flow of solids and sand from the horizontal section of the wells, have fully recovered drilling fluids, are continuing to clean up, and are selling oil. Production performance to date is promising with the "fish-bone" design recording an IP30 of 134 bbl/d gross and current production of 150 bbl/d gross (field estimate). The single lined lateral well is currently producing at 75 bbl/d gross (field estimate). Learnings from these two wells will confirm type curve assumptions, inform mapping parameters, geological cutoffs, and the future well design for optimum economic development of both the GP and Sparky sands in the Mannville Stack at Frog Lake.

The rig at Frog Lake will remain active and focused on the drilling of Waseca South, Sparky, and GP sands for the remainder of 2025.

Marten Hills

The Company commenced a "bottoms up" waterflood pilot at Marten Hills during the second quarter of 2025, with water injection initiated at its first injection well in April. Value is expected to be realized through reduced water handling costs, reduced production declines and enhanced reserve recoveries.

East Edson

Net production at East Edson was close to flat quarter-over-quarter, averaging 3,291 boe/d for the third quarter, (Q2 2025 - 3,269 boe/d).

Non-operated drilling commenced in the third quarter and 2 gross (1.0 net) wells were drilled, completed, and brought on stream. The average IP30 (gross) for the two wells was 1,165 boe/d as compared to the McDaniel Type Curve[2] of 1,003 boe/d, meeting expectations. An additional 2 gross (1.0 net) wells are expected to be drilled and placed on production prior to year end.

Other Exploration

In addition to exploration activities in the GP and Sparky zones at Frog Lake and the Sparky zone at Figure Lake, the Company is continuing to advance multiple additional new venture exploration prospects, pursuing both land capture and play concept de-risking activities while minimizing risked capital exposure. A total of $0.3 million was invested in the third quarter of 2025 to acquire seismic data for exploratory prospects that are expected to be evaluated in the next 12 months.

(1) No wells were excluded from the calculation of average results except the criteria for producing days.
(2) Type curve assumptions for the 33m spacing well design are based on the Total Proved plus Probable Undeveloped reserves contained in the 2024 McDaniel Reserve Report as disclosed in the Company's 2024 Annual Information Form available under the Company's profile on SEDAR+ at www.sedarplus.ca. "McDaniel" means McDaniel & Associates Consultants Ltd. independent qualified reserves evaluators. "McDaniel Reserve Report" means the independent engineering evaluation of the heavy crude oil and conventional natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2024 and a preparation date of March 10, 2025. See "Estimated Drilling Locations".
(3) Assuming a September 30, 2025, reference date, management estimates 260.2 net locations in the greater Figure Lake area, 65.6 net locations are recognized in the 2024 Year-End McDaniel Report as proved undeveloped and an additional 30.6 net locations are classified as probable undeveloped. The Company estimates a total of 326.2 net heavy oil development locations, 93.1 of which are proved and 45.6 are probable and included in the McDaniel Reserve Report. The following net reserve locations have been drilled through 2025: 8.0 proved undeveloped in Figure Lake, 4.5 proved undeveloped and 4.5 probable undeveloped in North Waseca, and 3.0 proved undeveloped in South Waseca.

OUTLOOK AND GUIDANCE

For the fourth quarter of 2025, Rubellite plans to spend a total of $30 to $35 million on exploration and development capital expenditures[1], bringing total spending for the year to $110 to $115 million. This increase over previous full year guidance of $100 to $110 million reflects: (1) the increased working interest from 50% to 100% for the drilling of four of seven gross wells at Frog Lake in the third quarter (two of the four 100% working interest wells were incorporated in previous guidance); (2) oil battery consolidation and facilities investments at Frog Lake to free up equipment for new pads and to reduce operating expenses; (3) accelerated non-operated spending at Edson on pipeline infrastructure for the Q1 2026 drilling program; (4) construction of additional surface pads at both Frog Lake and Figure Lake to optimize capital program execution; and (5) acquisition of additional bitcoin mining equipment to reduce flaring and monetize stranded solution gas.

Rubellite's fourth quarter capital program includes:

At Figure Lake:
- Drilling of 4 gross (4.0 net) Clearwater 15,000m development wells remaining on the 9-35 Pad;
- Drilling of 1 gross (1.0 net) Clearwater 8,500m producing well and one (1.0 net) single leg waterflood injector;
- Drilling of 1 gross (1.0 net) Sparky exploration well; and
- Core testing on a new core cut at the 9-35 Pad to progress enhanced oil recovery.

At Frog Lake:
- Drilling of 4 gross (2.0 net) South Waseca wells;
- Drilling of 2 gross (1.0 net) GP exploration wells;
- Drilling of 1 gross (0.5 net) exploratory Sparky well; and
- Preliminary spending towards the acquisition of 3D seismic to better define geologically complex Mannville-Stack targets.

At East Edson:
- Participation in the drilling of 2 gross (1.0 net) Wilrich development wells to complete the 2025 drilling program.

Despite the ongoing volatility in oil prices, Rubellite is planning to maintain the operational efficiencies of its one rig drilling programs at each of Figure Lake and Frog Lake for the remainder of 2025, and to advance strategic initiatives such as land continuation and new capture, secondary recovery and exploration. The Company will continue to strive for meaningful per well capital cost reductions to maintain attractive rates of return and payout periods, and will manage its capital spending to prioritize free funds flow generation over production growth in this current weaker oil price environment.

Heavy oil sales volumes based on the current plan are expected to grow 47% to 50% year-over-year to average between 8,325 - 8,400 bbl/d in 2025, up from previous guidance of between 8,200 - 8,400 bbl/d. Total production sales volumes, including natural gas and NGL volumes at East Edson and Figure Lake, are forecast to average 12,325 - 12,400 boe/d in 2025, up from previous guidance of 12,200 - 12,400 boe/d.

Capital spending activity will continue to be funded from adjusted funds flow(1) combined with proceeds from the sale of undeveloped land, with excess free funds flow(1) used to reduce net debt(1) and for other balance sheet obligations. Aided by Rubellite's extensive commodity price risk management positions, the Company continues to forecast strong adjusted funds flow and free funds flow through the fourth quarter of 2025 based on the forward market for commodity prices as at November 5, 2025.

Rubellite's Clearwater and Mannville Stack production continues to realize an attractive offset to WCS benchmark pricing, resulting in a further improvement to its heavy oil wellhead differential guidance to a range of $3.75 to $4.00 per bbl, down from $4.00 to $4.50 per bbl previously. Initiatives to improve field operating costs have improved the Company's operating cost guidance to a range of $6.50 to $7.00 per boe as compared to $6.50 to $7.25 per boe previously. Additionally, transportation costs were normalized across operations during the third quarter, driving guidance for annual transportation costs down to $5.25 - $5.50 per boe versus $5.50 - $6.00 per boe previously.

Rubellite will continue to address end of life ARO, with total abandonment and reclamation expenditures of approximately $0.5 million planned for the fourth quarter of 2025. In combination with the $1.3 million of asset retirement obligation spending in the first three quarters of 2025, the Company is on track to exceed its Alberta Energy Regulator ("AER") area-based mandatory spending requirement for 2025 of $1.7 million.

(1) Non-GAAP financial measure, non-GAAP ratio or supplementary financial measure. See "Non-GAAP and Other Financial Measures".

Capital spending and drilling activity for 2025 is summarized in the table below:

	Q1 - Q3 2025		**Q4 2025**		**Full year 2025**	
	Capital Expenditures (millions)	**# of wells (gross/net)**	**Capital Expenditures (millions)**	**# of wells (gross/net)**	**Capital Expenditures (millions)**	**# of wells (gross/net)**
Figure Lake(1)		14 / 14.0		6 / 6.0		20 / 20.0
Frog Lake(2)		19 / 14.0		7 / 3.5		26 / 17.5
Marten Hills		1 / 0.3		- / -		1 / 0.3
East Edson		2 / 1.0		2 / 1.0		4 / 2.0
Exploration		1 / 1.0		- / -		1 / 1.0
Total(3)	**$80.0**	**37 / 30.3**	**$30 - $35**	**15 / 10.5**	**$110 - $115**	**52 / 40.8**

(1) Includes one waterflood injection well.
(2) Includes 5 gross (3.0 net) wells at Frog Lake targeting secondary exploration zones.
(3) Excludes abandonment and reclamation spending, acquisitions and land expenditures, if any.

Rubellite’s capital spending, drilling and operational guidance for 2025 are presented in the table below:

	Previous Full Year 2025 Guidance(1)	Full Year 2025 Guidance
Sales Production (boe/d)	12,200 - 12,400	12,325 - 12,400
Production mix (% oil and liquids)(2)	70%	70%
Heavy Oil Production (bbl/d)	8,200 - 8,400	8,325 - 8,400
Exploration and Development spending ($ millions)(3)(4)	$100 - $110	$110 - $115
Heavy oil wellhead differential ($/bbl)(3)	$4.00 - $4.50	$3.75 - $4.00
Royalties (% of revenue)(3)	13% - 14%	13% - 14%
Production and operating costs ($/boe)(3)	$6.50 - $7.25	$6.50 - $7.00
Transportation costs ($/boe)(3)	$5.50 - $6.00	$5.25 - $5.50
General and administrative costs ($/boe)(3)	$3.00 - $3.50	$3.00 - $3.50

(1) Previous full year 2025 guidance dated August 5, 2025.
(2) Liquids means oil, condensate, ethane, propane and butane.
(3) Non-GAAP financial measure, non-GAAP ratio or supplementary financial measure. See "Non-GAAP and Other Financial Measures".
(4) Excludes land and acquisition spending, if any.

Susan Riddell Rose

Susan Riddell Rose
President and Chief Executive Officer
November 5, 2025

SUMMARY OF QUARTERLY RESULTS

	Three months ended September 30,		Nine months ended September 30,	
	2025	2024	**2025**	2024
Financial				
Oil revenue	**58,290**	43,682	**185,439**	109,303
Net income and comprehensive income	**5,646**	15,010	**22,857**	23,225
Per share – basic(1)	**0.06**	0.23	**0.25**	0.37
Per share – diluted(1)	**0.06**	0.23	**0.24**	0.36
Total Assets	**558,709**	432,836	**558,709**	432,836
Cash flow from operating activities	**34,953**	19,973	**97,896**	56,386
Adjusted funds flow(2)	**35,663**	23,029	**108,908**	62,145
Per share – basic(1)(2)	**0.38**	0.35	**1.17**	0.98
Per share – diluted(1)(2)	**0.37**	0.35	**1.14**	0.96
Adjusted funds flow, before transaction costs(2)(6)	**35,663**	25,039	**108,908**	64,155
Per share – basic(1)(2)	**0.38**	0.37	**1.17**	1.00
Per share – diluted(1)(2)	**0.37**	0.37	**1.14**	0.99
Q3 annualized adjusted funds flow(2)(7)	**142,652**	100,156	**142,652**	100,156
Net debt to Q3 annualized adjusted funds flow ratio(2)(7)	**1.0**	1.5	**1.0**	1.5
Net debt(2)	**138,354**	147,939	**138,354**	147,939
Capital expenditures(2)				
Capital expenditures, including land, corporate and other(2)	**35,365**	36,650	**91,465**	73,369
Acquisition(8)(9)	**—**	62,732	**—**	62,732
Proceeds on disposition(10)	**(5,500)**	—	**(5,500)**	—
Capital expenditures, after acquisition and dispositions(2)	**29,865**	99,382	**85,965**	136,101
Wells Drilled(3) – gross (net)	**14 / 11.5**	16 / 13.5	**37 / 30.3**	31 / 28.5
Common shares outstanding(1) *(thousands)*				
Weighted average – basic	**93,700**	65,834	**93,211**	63,592
Weighted average – diluted	**96,311**	66,571	**95,838**	64,599
End of period	**93,670**	67,593	**93,670**	67,593
Operating				
Heavy Oil (bbl/d)(4)	**8,338**	5,954	**8,438**	4,994
Natural gas (Mcf/d)	**20,975**	—	**21,174**	—
NGL (bbl/d)(5)	**288**	—	**342**	—
Daily average sales production (boe/d)	**12,122**	5,954	**12,309**	4,994
Average prices				
West Texas Intermediate (“WTI”) ($US/bbl)	**64.93**	75.09	**66.70**	77.54
Western Canadian Select (“WCS”) ($CAD/bbl)	**75.10**	83.95	**77.88**	84.45
AECO 5A Daily Index ($CAD/Mcf)	**0.63**	0.69	**1.50**	1.45
Rubellite average realized prices(2)(6)				
Oil ($/bbl)	**72.40**	79.75	**74.06**	79.88
Natural gas ($/Mcf)	**0.66**	—	**1.58**	—
NGL ($/bbl)	**56.12**	—	**60.85**	—
Average realized price(2) ($/boe)	**52.27**	79.75	**55.18**	79.88
Average realized price, after risk management contracts(2) ($/boe)	**55.83**	80.06	**57.74**	79.46

(1) Per share amounts are calculated using the weighted average number of basic or diluted common shares.
(2) Non-GAAP measure or ratio. See "Non-GAAP and other Financial Measures" contained in this interim report.
(3) Well count reflects wells rig released during the period.
(4) Conventional heavy oil sales production excludes tank inventory volumes.
(5) Liquids means oil, condensate, ethane and butane.
(6) Before risk management contracts; supplementary financial measure. See "Non-GAAP and Other Financial Measures".
(7) Based on Q3 2025 and Q3 2024 annualized adjusted funds flow before transaction costs relative to period end net debt. Non-GAAP financial measure and ratio.

ADVISORIES

This third quarter 2025 interim report refers to certain non-GAAP measures and metrics commonly used in the oil and natural gas industry and provides forward-looking information and statements. Further detailed information regarding these measures is provided in this report in "*Management's Discussion and Analysis – NON-GAAP AND OTHER FINANCIAL MEASURES*" on pages 21 to 24 and "*Management's Discussion and Analysis – FORWARD-LOOKING INFORMATION*" on pages 24 and 25.

In addition to the disclosure set out in the Company's Management's Discussion and Analysis for the period ended September 30, 2025, we provide certain supplementary disclosure throughout this report in respect of certain specified financial measures (as such term is defined in National Instrument 51-112 – *Non-GAAP and Other Financial Measures*) and in respect of certain oil and gas metrics.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of Rubellite Energy Corp.'s ("Rubellite", the "Company" or the "Corporation") operating and financial results for the three and nine months ended September 30, 2025, as well as the information and estimates concerning the Corporation's future outlook based on currently available information. This discussion should be read in conjunction with the Corporation's unaudited condensed interim consolidated financial statements and accompanying notes for the three and nine months ended September 30, 2025 *as well as the audited consolidated financial statements and accompanying notes for the year ended December 31, 2024. Disclosure, which is unchanged from the December 31, 2024 MD&A has not been duplicated herein. The Corporation's financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") which require publicly accountable enterprises to prepare their financial statements using IFRS Accounting Standards ("IFRS")* as issued by the International Accounting Standards Board*. The date of this MD&A is November 5, 2025.*

This MD&A contains specified financial measures that are not recognized by GAAP and used by management to evaluate the performance of the Corporation and its business. Since certain specified financial measures may not have a standardized meaning, securities regulations require that specified financial measures are clearly defined, qualified and, where required, reconciled with their nearest GAAP measure. See "Non-GAAP and Other Financial Measures" for further information on the definition, calculation and reconciliation of these measures. This MD&A also contains "Forward-Looking Information". Readers are also referred to the other advisory sections at the end of this MD&A for additional information.

NATURE OF BUSINESS

The Company is a Canadian energy company headquartered in Calgary, Alberta engaged in the exploration, development, production and marketing of its diversified asset portfolio which includes conventional heavy crude oil from the Clearwater and Mannville Stack Formations in Eastern Alberta, liquids-rich conventional natural gas assets in the deep basin of West Central Alberta, and undeveloped bitumen leases in Northern Alberta. The Company is pursuing a robust growth plan focused on heavy oil exploration and development utilizing multi-lateral, horizontal drilling technology, targeting superior corporate returns and free funds flow generation while maintaining a conservative capital structure and prioritizing operational excellence. Additional information on the Company can be accessed on the Company's website at www.rubelliteenergy.com or on SEDAR+ at www.sedarplus.ca.

The Company's common shares trade on the Toronto Stock Exchange under the symbol "RBY".

Prior Transactions

Recombination Transaction

On October 31, 2024, the Company, Rubellite Energy Inc. and Perpetual Energy Inc. ("Perpetual") closed a recombination transaction by way of an arrangement under Section 193 of the Business Corporations Act (Alberta) (the "Recombination Transaction"). Comparative figures in the MD&A include Rubellite Energy Inc.'s results prior to the business combination and do not reflect any historical data from Perpetual. The conventional natural gas assets at East Edson acquired through the Recombination Transaction are included in the West Central cash generating unit ("CGU"). This MD&A contains certain information pertaining to the Company before and after giving effect to the Recombination Transaction. Any reference to information prior to October 31, 2024 are references to Rubellite Energy Inc. and any reference to information subsequent to October 31, 2024 are references to the Company. Accordingly, unless the context otherwise requires, references to the Company subsequent to October 31, 2024 shall mean "Rubellite Energy Corp." and references to the Corporation prior to October 31, 2024 shall mean "Rubellite Energy Inc".

Buffalo Mission Acquisition

On August 2, 2024, Rubellite closed the acquisition of Buffalo Mission Energy Corp. ("Buffalo Mission") (the "BMEC Acquisition"), a private Mannville Stack-focused heavy oil producer in the Frog Lake area. The total consideration paid was $96.6 million, inclusive of $23.5 million of assumed net debt, which consisted of $62.7 million in cash and the issuance of 5.0 million common shares of Rubellite to certain shareholders of Buffalo Mission.

THIRD QUARTER 2025 OPERATIONAL AND FINANCIAL HIGHLIGHTS

Sales Production Volumes

- Conventional heavy oil sales production averaged 8,338 bbl/d, a 40% increase from the third quarter of 2024 (Q3 2024 - 5,954 bbl/d).
- Total sales production averaged 12,122 boe/d (71% heavy oil and natural gas liquids ("NGL")), a 104% increase from the third quarter of 2024 (Q3 2024 - 5,954 boe/d (100% heavy oil)).
- Rubellite brought 11 gross (9.0 net) heavy oil wells on production at Figure Lake and Frog Lake during the quarter.
- The Company's West Central 2025 drilling program commenced in July, adding 2 gross (1.0 net) liquids-rich conventional natural gas wells at East Edson to sales production late in the third quarter.
- Natural gas sales through the Figure Lake gas plant, operational since January 23, 2025, averaged 2.9 MMcf/d and 4 bbl/d of associated NGL.

Capital Expenditures

- Exploration and development capital expenditures(1) totaled $33.7 million to drill, complete, equip and tie-in 5 gross (5.0 net) multi-lateral horizontal development wells at Figure Lake, 7 gross (5.5 net) multi-lateral horizontal development wells at Frog Lake and 2 gross (1.0 net) liquids-rich conventional natural gas wells at East Edson.
- Exploration and development spending also included $1.5 million to expand the Figure Lake gas plant and gas gathering system, increasing capacity from 3.0 MMcf/d to 6.4 MMcf/d.
- Land and other spending totaled $1.5 million and included $0.2 million for seismic purchases (Q3 2024 - $2.9 million). In addition to land purchases during the quarter, the Company sold undeveloped land for proceeds of $5.5 million which served to fund other capital activities and reduce net debt. Subsequent to the end of the third quarter, Rubellite closed the sale of additional undeveloped land for $2.3 million.
- Decommissioning, abandonment and reclamation spending totalled $0.4 million during the third quarter of 2025 (Q3 2024 - $0.2 million).

Financial Performance

- Adjusted funds flow[1] was $35.7 million ($0.38 per share), up 55% (9% per share) from the third quarter of 2024 (Q3 2024 - $23.0 million or $0.35 per share).
- Cash costs[1] were $18.6 million or $16.66/boe, down 33% on a per boe basis from the third quarter of 2024 (Q3 2024 - $13.5 million or $24.72/boe).
- Net income for the quarter was $5.6 million ($0.06 per share) compared to $15.0 million net income ($0.23 per share) in the third quarter of 2024.

Balance Sheet and Liquidity

- As at September 30, 2025, net debt[1] was $138.4 million, a 10% reduction from $154.0 million as at December 31, 2024, driven by $17.4 million of positive free funds flow[1] during the first nine months of 2025 combined with $5.5 million of proceeds from the sale of undeveloped land which was used to reduce net debt and other balance sheet obligations.
- Rubellite had available liquidity[2] at September 30, 2025 of $48.0 million, comprised of the $140.0 million borrowing limit of Rubellite's first lien credit facility, less current bank borrowings of $90.6 million and outstanding letters of credit of $1.4 million.

(1) Non-GAAP financial measure, non-GAAP ratio or supplementary financial measure. See "Non-GAAP and Other Financial Measures".
(2) See "Liquidity, Capitalization and Financial Resources - Capital Management".

OPERATIONS UPDATE

Greater Figure Lake (Figure Lake and Edwand)

Heavy oil sales production from the Greater Figure Lake area averaged 5,110 bbl/d for the third quarter (Q2 2025 - 5,544 bbl/d). Additionally, gas sales contributed 2.9 MMcf/d plus associated natural gas liquids of 4 bbl/d which brought total sales production at Figure Lake for the third quarter to 5,601 boe/d (91% oil and liquids) (Q2 2025 - 6,064 bbl/d; 92% oil and liquids). Rubellite completed the expansion of the Figure Lake 1-13 Gas Plant to manage additional associated gas volumes in late August, establishing total throughput capacity of approximately 6.4 MMcf/d.

During the third quarter of 2025, Rubellite drilled and rig released 4 gross (4.0 net) development horizontal wells from the 9-35-63-18W4 pad (the "9-35 Pad"), all targeting the Wabiskaw Member of the Clearwater Formation, with 33 meter inter-leg spacing and 15,000m open hole length per the Figure Lake well design adopted in the latter half of 2024. Results from the 2025 development capital program to date across the Greater Figure Lake field continue to outperform expectations, with an average[1] IP30 of 259 bbl/d (9 wells) and IP60 of 239 bbl/d (8 wells), as compared to the McDaniel Tier 1 Type Curve[2] rates for 33 meter inter-leg spacing of 177 bbl/d (IP30) and 169 bbl/d[2] (IP60).

In addition to development drilling in the third quarter, 1 gross (1.0 net) step-out delineation well was drilled in the Edwand region with 50m inter-leg spacing and ~10,000m open hole length, to test and confirm productivity from a new pool in the Wabiskaw Member. The step-out well achieved an IP30 and IP60 of 48 bbl/d and 36 bbl/d, respectively.

Development drilling is continuing through the fourth quarter from the 9-35 Pad, including one waterflood pilot pattern consisting of a single horizontal multi-lateral well with two sets of four legs each (8 legs in total), with ~165 meters between the four-leg sets. Each 4-leg set will be drilled with 33 meter inter-leg spacing, and the waterflood producer well will have a planned total open hole length for the 8 legs of approximately 8,500 meters. A separate single leg water injection well will be drilled along the center line between the two 4-leg sets, and water injection is expected to commence in early 2026.

The Company advanced its novel natural gas-based re-injection pilot at Figure Lake for enhanced oil recovery, with an experimental well now configured at the 01-13-063-18W4 pad (the "1-13 Pad"), on the same site as the Figure Lake 1-13 Gas Plant. A total of ~25 MMcf of natural gas was injected into an existing open-hole multi-lateral well in order to confirm injectivity. Natural gas is being flowed back at controlled rates in advance of a second injection test, after which the well will be reconfigured for heavy oil production. Results from the waterflood pilot and natural gas-based re-injection experiment will inform future development patterns and enhanced oil recovery techniques to be implemented across the Greater Figure Lake area.

Rubellite also commenced testing larger diameter (200mm) boreholes at the 9-35 Pad to determine if incremental economic returns associated with improved inflow and productivity can be realized relative to the robust economics established for the existing 159mm boreholes drilled to date at Figure Lake. A total of 3 gross (3.0 net) wells with the 200mm borehole diameter will be drilled by year end.

A Sparky exploration well at Figure Lake is planned for the fourth quarter of 2025. If successful, there are approximately 15.0 net follow-up Sparky locations which would be incremental to the existing Clearwater development inventory.

During the third quarter, the Company was successful in acquiring 4.0 net sections of land. With the additional acreage, and adjusted to reflect both 2025 step-out and development drilling activity, Rubellite has an inventory of 260.2 net development locations[3] identified in the Wabiskaw, including 88.2 net proven and probable undeveloped[2][3] booked locations. Under a one-rig program, which would provide for the drilling of 18 wells per year at Figure Lake, the Clearwater location count at Figure Lake represents ~14 years of low-risk development drilling inventory.

Frog Lake

Production at the Frog Lake property averaged 2,697 bbl/d (100% heavy oil) for the third quarter of 2025, a 6% increase from the second quarter of 2025 (Q2 2025 2,539 bbl/d).

During the third quarter, 1 gross (1.0 net) Waseca North well, 4 gross (3.0 net) Waseca South wells, and 2 gross (1.5 net) exploratory General Petroleum ("GP") wells were drilled, for a total of 7 gross (5.5 net) wells.

Rubellite switched its drilling operations at Frog Lake in December 2024 to utilize OBM. The OBM trial at Frog Lake has confirmed the benefits of using OBM fluid consistent with Rubellite's operations at Figure Lake, where the use of OBM has modestly reduced the cost of the mud system net of recovered OBM suitable for re-use and the sales credit for OBM that is not fit for re-use. Additional benefits include improved hole cleaning and stability, accelerated time to stabilized reservoir production, reduced drill pipe wear, and reduced water handling and disposal costs as compared to conventional water-based mud systems. The Company is continuing to utilize OBM in its ongoing drilling operations at Frog Lake as it evaluates the effects on long term production performance in different formations across the Frog Lake field.

Results thus far from the 2025 capital drilling program targeting the Waseca North sand at Frog Lake (13 gross (9.5 net) wells) have achieved an average[1] IP30 and IP60 of 133 bbl/d (13 wells) and 113 bbl/d (13 wells) respectively, as compared to the McDaniel Waseca North Type

Curve(2) IP30 and IP60 of 107 bbl/d and 104 bbl/d established by McDaniel at year-end 2024 using historical data obtained from wells drilled with water-based mud systems.

2 gross (2.0 net) of the 4 gross (3.0 net) South Waseca sand wells drilled in the third quarter, have achieved an average IP30 of 159 bbl/d as compared to the McDaniel South Type Curve(2) of 150 bbl/d, while the remaining wells are either still recovering load fluid or are within the 30 day initial production period.

In addition to continued drilling of the Waseca sand as the primary development zone at Frog Lake, the Company drilled 2 gross (1.5 net) exploratory wells in the third quarter of 2025, targeting the GP sand. One gross (0.5 net) was drilled using a single leg lined horizontal lateral design and one gross (1.0 net) was drilled with a lined "fish bone" design. Both wells were equipped with recycle strings to aid in the flow of solids and sand from the horizontal section of the wells, have fully recovered drilling fluids, are continuing to clean up, and are selling oil. Production performance to date is promising with the “fish-bone” design recording an IP30 of 134 bbl/d gross and current production of 150 bbl/d gross (field estimate). The single lined lateral well is currently producing at 75 bbl/d gross (field estimate). Learnings from these two wells will confirm type curve assumptions, inform mapping parameters, geological cutoffs, and the future well design for optimum economic development of both the GP and Sparky sands in the Mannville Stack at Frog Lake.

The rig at Frog Lake will remain active and focused on the drilling of Waseca South, Sparky, and GP sands for the remainder of 2025.

Marten Hills

The Company commenced a "bottoms up" waterflood pilot at Marten Hills during the second quarter of 2025, with water injection initiated at its first injection well in April. Value is expected to be realized through reduced water handling costs, reduced production declines and enhanced reserve recoveries.

East Edson

Net production at East Edson was close to flat quarter-over-quarter, averaging 3,291 boe/d for the third quarter, (Q2 2025 - 3,269 boe/d).

Non-operated drilling commenced in the third quarter and 2 gross (1.0 net) wells were drilled, completed, and brought on stream. The average IP30 (gross) for the two wells was 1,165 boe/d as compared to the McDaniel Type Curve(2) of 1,003 boe/d, meeting expectations. An additional 2 gross (1.0 net) wells are expected to be drilled and placed on production prior to year end.

Other Exploration

In addition to exploration activities in the GP and Sparky zones at Frog Lake and the Sparky zone at Figure Lake, the Company is continuing to advance multiple additional new venture exploration prospects, pursuing both land capture and play concept de-risking activities while minimizing risked capital exposure. A total of $0.3 million was invested in the third quarter of 2025 to acquire seismic data for exploratory prospects that are expected to be evaluated in the next 12 months.

(1) No development wells were excluded from the calculation of average results except by the criteria for producing days.
(2) Type curve assumptions for the 33 meter spacing well design are based on the Total Proved plus Probable Undeveloped reserves contained in the 2024 McDaniel Reserve Report as disclosed in the Company’s 2024 Annual Information Form available under the Company’s profile on SEDAR+ at www.sedarplus.ca. “McDaniel” means McDaniel & Associates Consultants Ltd. independent qualified reserves evaluators. “McDaniel Reserve Report” means the independent engineering evaluation of the heavy crude oil and conventional natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2024 and a preparation date of March 10, 2025. See "Estimated Drilling Locations.
(3) Assuming a September 30, 2025, reference date, management estimates 260.2 net locations in the greater Figure Lake area, 65.6 net locations are recognized in the 2024 Year-End McDaniel Report as proved undeveloped and an additional 30.6 net locations are classified as probable undeveloped. The Company estimates a total of 326.2 net heavy oil development locations, 93.1 of which are proved and 45.6 are probable and included in the McDaniel Reserve Report. The following net reserve locations have been drilled through 2025: 8.0 proved undeveloped in Figure Lake, 4.5 proved undeveloped and 4.5 probable undeveloped in North Waseca, and 3.0 proved undeveloped in South Waseca.

OUTLOOK AND GUIDANCE

For the fourth quarter of 2025, Rubellite plans to spend a total of $30 to $35 million on exploration and development capital expenditures(1), bringing total spending for the year to $110 to $115 million. This increase over previous full year guidance of $100 to $110 million reflects: (1) the increased working interest from 50% to 100% for the drilling of four of seven gross wells at Frog Lake in the third quarter (two of the four 100% working interest wells were incorporated in previous guidance); (2) oil battery consolidation and facilities investments at Frog Lake to free up equipment for new pads and to reduce operating expenses; (3) accelerated non-operated spending at Edson on pipeline infrastructure for the Q1 2026 drilling program; (4) construction of additional surface pads at both Frog Lake and Figure Lake to optimize capital program execution; and (5) acquisition of additional bitcoin mining equipment to reduce flaring and monetize stranded solution gas.

Rubellite's fourth quarter capital program includes:

At Figure Lake:
- Drilling of 4 gross (4.0 net) Clearwater 15,000m development wells remaining on the 9-35 Pad;
- Drilling of 1 gross (1.0 net) Clearwater 8,500m producing well and one (1.0 net) single leg waterflood injector;
- Drilling of 1 gross (1.0 net) Sparky exploration well; and
- Core testing on a new core cut at the 9-35 Pad to progress enhanced oil recovery.

At Frog Lake:
- Drilling of 4 gross (2.0 net) South Waseca wells;
- Drilling of 2 gross (1.0 net) GP exploration wells;
- Drilling of 1 gross (0.5 net) exploratory Sparky well; and
- Preliminary spending towards the acquisition of 3D seismic to better define geologically complex Mannville-Stack targets.

At East Edson:
- Participation in the drilling of 2 gross (1.0 net) Wilrich development wells to complete the 2025 drilling program.

Despite the ongoing volatility in oil prices, Rubellite is planning to maintain the operational efficiencies of its one rig drilling programs at each of Figure Lake and Frog Lake for the remainder of 2025, and to advance strategic initiatives such as land continuation and new capture, secondary recovery and exploration. The Company will continue to strive for meaningful per well capital cost reductions to maintain attractive rates of return and payout periods, and will manage its capital spending to prioritize free funds flow generation over production growth in this current weaker oil price environment.

Heavy oil sales volumes based on the current plan are expected to grow 47% to 50% year-over-year to average between 8,325 - 8,400 bbl/d in 2025, up from previous guidance of between 8,200 - 8,400 bbl/d. Total production sales volumes, including natural gas and NGL volumes at East Edson and Figure Lake, are forecast to average 12,325 - 12,400 boe/d in 2025, up from previous guidance of 12,200 - 12,400 boe/d.

Capital spending activity will continue to be funded from adjusted funds flow[1] combined with proceeds from the sale of undeveloped land, with excess free funds flow[1] used to reduce net debt[1] and for other balance sheet obligations. Aided by Rubellite's extensive commodity price risk management positions, the Company continues to forecast strong adjusted funds flow and free funds flow through the fourth quarter of 2025 based on the forward market for commodity prices as at November 5, 2025.

Rubellite's Clearwater and Mannville Stack production continues to realize an attractive offset to WCS benchmark pricing, resulting in a further improvement to its heavy oil wellhead differential guidance to a range of $3.75 to $4.00 per bbl, down from $4.00 to $4.50 per bbl previously. Initiatives to improve field operating costs have improved the Company's operating cost guidance to a range of $6.50 to $7.00 per boe as compared to $6.50 to $7.25 per boe previously. Additionally, transportation costs were normalized across operations during the third quarter, driving guidance for annual transportation costs down to $5.25 - $5.50 per boe versus $5.50 - $6.00 per boe previously.

Rubellite will continue to address end of life ARO, with total abandonment and reclamation expenditures of approximately $0.5 million planned for the fourth quarter of 2025. In combination with the $1.3 million of asset retirement obligation spending in the first three quarters of 2025, the Company is on track to exceed its Alberta Energy Regulator ("AER") area-based mandatory spending requirement for 2025 of $1.7 million.

(1) Non-GAAP financial measure, non-GAAP ratio or supplementary financial measure. See "Non-GAAP and Other Financial Measures".

Capital spending and drilling activity for 2025 is summarized in the table below:

	Q1 - Q3 2025		**Q4 2025**		**Full year 2025**	
	Capital Expenditures (millions)	**# of wells (*gross/net*)**	**Capital Expenditures (millions)**	**# of wells (*gross/net*)**	**Capital Expenditures (millions)**	**# of wells (*gross/net*)**
Figure Lake[1]		14 / 14.0		6 / 6.0		20 / 20.0
Frog Lake[2]		19 / 14.0		7 / 3.5		26 / 17.5
Marten Hills		1 / 0.3		- / -		1 / 0.3
East Edson		2 / 1.0		2 / 1.0		4 / 2.0
Other Exploration		1 / 1.0		- / -		1 / 1.0
Total[3]	**$80**	**37 / 30.3**	**$30 - $35**	**15 / 10.5**	**$110 - $115**	**52 / 40.8**

(1) Includes one waterflood injection well and 1 (1.0 net) well targeting the exploratory Sparky zone.
(2) Includes 5 gross (3.0 net) wells at Frog Lake targeting secondary exploration zones.
(3) Excludes abandonment and reclamation spending, acquisitions and land expenditures, if any.

Rubellite's capital spending, drilling and operational guidance for 2025 are presented in the table below:

	Previous Full Year 2025 Guidance[1]	Full Year 2025 Guidance
Sales Production (boe/d)	12,200 - 12,400	12,325 - 12,400
Production mix (% liquids)[2]	70%	70%
Heavy Oil Production (bbl/d)	8,200 - 8,400	8,325 - 8,400
Exploration and Development spending ($ millions)[3][4]	$100 - $110	$110 - $115
Heavy oil wellhead differential ($/bbl)[3]	$4.00 - $4.50	$3.75 - $4.00
Royalties (% of revenue)[3]	13% - 14%	13% - 14%
Production and operating costs ($/boe)[3]	$6.50 - $7.25	$6.50 - $7.00
Transportation costs ($/boe)[3]	$5.50 - $6.00	$5.25 - $5.50
General and administrative costs ($/boe)[3]	$3.00 - $3.50	$3.00 - $3.50

(1) Previous full year 2025 guidance dated August 5, 2025.
(2) Liquids means oil, condensate, ethane, propane and butane.
(3) Non-GAAP financial measure, non-GAAP ratio or supplementary financial measure. See "Non-GAAP and Other Financial Measures".
(4) Excludes land and acquisition spending.

THIRD QUARTER 2025 FINANCIAL AND OPERATING RESULTS

Capital Expenditures

Rubellite uses capital expenditures to measure its capital investments compared to the Company's annual budgeted expenditures related to both property, plant and equipment assets ("PP&E") and exploration and evaluation assets ("E&E") assets. The capital budget excludes acquisition and disposition activities. "Capital Expenditures" is not a standardized measure; therefore, may not be comparable with the calculation of similar measures by other entities. For a reconciliation of cash flow used in investing activities to capital expenditures, refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this MD&A.

The following tables summarize capital expenditures for both PP&E and E&E assets, excluding non-cash items:

	Three months ended September 30,					
		2025			2024	
(*$ thousands*)	**E&E**	**PP&E**	**Total**	E&E	PP&E	Total
Drilling and completions	**42**	**27,941**	**27,983**	5,033	23,443	28,476
Facilities	**(31)**	**5,751**	**5,720**	363	4,829	5,192
Capital expenditures(1)	**11**	**33,692**	**33,703**	5,396	28,272	33,668
Land and other	**301**	**1,162**	**1,463**	2,854	76	2,930
Corporate	**—**	**199**	**199**	—	52	52
Capital expenditures, including land and other(1)	**312**	**35,053**	**35,365**	8,250	28,400	36,650

(1) Capital expenditures is a non-GAAP measure. See "Non-GAAP and Other Financial Measures".

	Nine months ended September 30,					
		2025			2024	
(*$ thousands*)	**E&E**	**PP&E**	**Total**	E&E	PP&E	Total
Drilling and completions	**1,079**	**65,498**	**66,577**	8,803	47,681	56,484
Facilities	**236**	**12,969**	**13,205**	492	10,358	10,850
Capital expenditures(1)	**1,315**	**78,467**	**79,782**	9,295	58,039	67,334
Land and other	**5,347**	**5,940**	**11,287**	2,990	76	3,066
Corporate	**—**	**396**	**396**	—	2,969	2,969
Capital expenditures, including land and other(1)	**6,662**	**84,803**	**91,465**	12,285	61,084	73,369

(1) Capital expenditures is a non-GAAP measure. See "Non-GAAP and Other Financial Measures".

Capital expenditures by CGU

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	**2025**	2024	**2025**	2024
Eastern Heavy Oil	**28,992**	36,598	**83,949**	70,400
West Central	**6,174**	—	**7,120**	—
Capital expenditures(1), including land and other	**35,166**	36,598	**91,069**	70,400

(1) Excludes corporate capital expenditures; Non-GAAP measure. See "Non-GAAP and Other Financial Measures".

Wells drilled by area

	Three months ended September 30,		Nine months ended September 30,	
(gross/net)	**2025**	2024	**2025**	2024
Development				
Figure Lake(1)	**5 / 5.0**	11 / 11.0	**14 / 14.0**	25 / 25.0
Frog Lake(2)(3)	**7 / 5.5**	5 / 2.5	**19 / 14.0**	5 / 2.5
Marten Hills Waterflood Injection(4)	**-/-**	- / -	**1 / 0.3**	- / -
Edson	**2 / 1.0**	- / -	**2 / 1.0**	- / -
Exploration				
Other exploratory(5)	**- / -**	- / -	**1 / 1.0**	1 / 1.0
Total	**14 / 11.5**	16 / 13.5	**37 / 30.3**	31 / 28.5

(1) 1 gross (1.0 net) well drilled on the 9-35 Pad at Figure Lake was spud on September 29, 2025 and rig released October 17, 2025 and not included in the Q3 2025 well count.
(2) 1 gross (1.0 net) well drilled on the 14-19 Pad in Frog Lake was spud on September 23, 2025 and rig released on October 4, 2025 and not included in the Q3 2025 well count.
(3) Four wells drilled in Q3 2025 and nine wells drilled in the first nine months of 2025 were at 100% working interest as Frog Lake Energy Resources Corp. ("FLERC") has elected gross overriding royalty positions in these wells.
(4) 1 gross (0.3 net) injection waterflood well was drilled at Marten Hills on the 12-35 Pad during Q1 2025.
(5) 1 gross (1.0 net) horizontal evaluation well was drilled in Q1 2025 and 1 gross (1.0 net) vertical stratigraphic evaluation well was drilled in Q1 2024. The wells were transferred to E&E expense in Q1 2025.

Capital Expenditures

During the third quarter of 2025, Rubellite invested a total of $33.7 million in exploration and development activities, before land and other corporate spending, related primarily to drill, complete, equip and tie-in 5 gross (5.0 net) multi-lateral horizontal Clearwater wells at Figure Lake, 5 gross (4.0 net) multi-lateral horizontal Waseca wells and 2 gross (1.5 net) single leg lined GP wells at Frog Lake, and 2 gross (1.0 net) horizontal multi-frac Wilrich wells at East Edson. A portion of capital to drill 1 gross (1.0 net) additional well at Figure Lake and 1 gross (1.0 net) additional well at Frog Lake was spent during the third quarter with both wells rig released early in the fourth quarter. Facilities spending included $1.5 million for gas gathering and pipeline tie-ins at Figure Lake, supporting the solution gas conservation project.

During the first nine months of 2025, the Company spent $79.8 million on exploration and development activities, before land and other corporate spending, primarily related to the two rig program to drill, complete, equip and tie-in 14 gross (14.0 net) wells at Figure Lake, 19 gross (14.0 net) wells at Frog Lake, 1 gross (0.3 net) waterflood injection well at Marten Hills, 2 gross (1.0 net) wells at East Edson and 1 gross (1.0 net) exploratory evaluation well. Capital spending also included $3.4 million for facilities spending at Figure Lake for the solution gas conservation project and $0.9 million at East Edson for lease construction, facility improvements and pipelines to support the ongoing drilling program with the 50% joint venture partner.

Land and seismic purchases were $1.5 million in the third quarter of 2025, with total land and seismic spending in 2025 of $11.3 million to acquire core area lands prospective for Clearwater development and to capture acreage on multiple exploration prospects.

During the third quarter of 2025, the Company disposed of undeveloped lands for proceeds of $5.5 million and recorded a corresponding gain on disposition.

During the third quarter of 2025, Rubellite spent $0.4 million (Q3 2024 - nominal) on abandonment and reclamation projects, with total asset retirement obligation expenditures of $1.3 million (2024 - $0.1 million) during the first nine months of 2025. No additional reclamation certificates were received from the AER in the third quarter of 2025, maintaining the total at two certificates received to date in 2025 (2024 - nil).

Production

	Three months ended September 30,		Nine months ended September 30,	
	2025	2024	**2025**	2024
Sales volumes				
Heavy oil (bbl/d)	**8,338**	5,954	**8,438**	4,994
Natural gas (Mcf/d)(1)(2)	**20,975**	—	**21,174**	—
NGL (bbl/d)(2)	**288**	—	**342**	—
Total sales volumes (boe/d)	**12,122**	5,954	**12,309**	4,994

(1) Conventional natural gas production at East Edson yielded a heat content of 1.18 GJ/Mcf during the third quarter of 2025 (Q3 2024 - nil) resulting in higher realized natural gas prices on a $/Mcf basis.
(2) Primarily from West Central CGU which produces liquids-rich conventional natural gas.

Sales production for the three and nine months ended September 30, 2025 by CGU:

	Three months ended September 30,		Nine months ended September 30,	
	2025	2024	**2025**	2024
Sales volumes by CGU				
Eastern Heavy Oil (boe/d)(1)	**8,831**	5,954	**8,888**	4,994
West Central (boe/d)(2)	**3,291**	—	**3,421**	—
Total sales volumes (boe/d)	**12,122**	5,954	**12,309**	4,994

(1) Primarily from the Clearwater and Mannville Stack formations in Eastern Alberta, which includes gas sales production at Figure Lake which commenced in Q1 2025 and assets at Frog Lake that were acquired in Q3 2024.
(2) Acquired through the Recombination Transaction with Perpetual in Q4 2024, which includes assets at East Edson that produce liquids-rich conventional natural gas.

Sales production for the three and nine months ended September 30, 2025 increased by 6,168 boe/d (104%) and 7,315 boe/d (146%) from the comparative periods of 2024, driven by successful drilling programs, Figure Lake solution gas tie-in, the BMEC Acquisition at Frog Lake in the third quarter of 2024 and the Recombination Transaction with Perpetual in the fourth quarter of 2024. The Company has increased its previously announced guidance range to 8,325 to 8,450 bbl/d (previously 8,200 to 8,400 bbl/d) of heavy oil sales volumes and 12,325 to 12,400 boe/d (previously 12,200 to 12,400 boe/d) of total sales volumes.

During the first half of 2025, 21 gross (18.0 net) wells from the Eastern Heavy Oil drilling program began contributing to sales, with an additional 11 gross (9.0 net) wells added during the third quarter, resulting in a total of 32 gross (27.0 net) wells contributing to sales in 2025. At the end of the third quarter, 4 gross (3.5 net) additional wells were recovering OBM drilling fluid and not yet contributing to sales. The Company's West Central 2025 drilling program commenced in the third quarter, adding 2 gross (1.0 net) liquids-rich conventional natural gas wells to sales production late in the third quarter.

At Figure Lake, a new gas plant commenced operations on January 23, 2025 and added 2.9 MMcf/d and 2.7 MMcf/d of natural gas sales on average during the three and nine months ended September 30, 2025. For the three and nine months ended September 30, 2025, assets acquired through the Recombination Transaction at East Edson added 3,291 boe/d and 3,421 boe/d of natural gas and NGL sales production (Q3 2024 and 2024 - nil) and the Frog Lake assets acquired through the BMEC Acquisition in August 2024 added 2,697 bbl/d and 2,554 bbl/d of heavy oil sales production (Q3 2024 - 1,528 bbl/d; 2024 - 513 bbl/d).

As a result of the Recombination Transaction and Figure Lake solution gas conservation, Rubellite's sales product mix was comprised of 71% conventional heavy crude oil and NGL and 29% conventional natural gas during the three and nine months ended September 30, 2025 (2024 comparative periods - 100% conventional heavy crude oil).

Revenue

($ thousands, except as noted)	Three months ended September 30, 2025	Three months ended September 30, 2024	Nine months ended September 30, 2025	Nine months ended September 30, 2024
Oil and natural gas revenue				
Oil	**55,536**	43,682	**170,599**	109,303
Natural gas	**1,268**	—	**9,156**	—
NGL	**1,486**	—	**5,684**	—
Oil and natural gas revenue	**58,290**	43,682	**185,439**	109,303
Reference prices				
West Texas Intermediate (WTI) (US$/bbl)	**64.93**	75.09	**66.70**	77.54
Foreign Exchange rate (CAD$/US$)	**1.38**	1.36	**1.40**	1.36
WTI (CAD$/bbl)	**89.60**	102.12	**93.38**	105.45
Western Canadian Select (WCS) differential (US$/bbl)	**(10.39)**	(13.55)	**(11.11)**	(15.49)
WCS (CAD$/bbl)	**75.10**	83.95	**77.88**	84.45
Heavy oil differential (CAD$/bbl)	**2.70**	4.20	**3.82**	4.57
AECO 5A Daily Index (CAD$/GJ)	**0.60**	0.65	**1.42**	1.38
AECO 5A Daily Index (CAD$/Mcf)(1)	**0.63**	0.69	**1.50**	1.45
Rubellite average realized prices(2)				
Oil ($/bbl)	**72.40**	79.75	**74.06**	79.88
Natural gas ($/Mcf)	**0.66**	—	**1.58**	—
NGL ($/bbl)	**56.12**	—	**60.85**	—
Average realized price ($/boe)	**52.27**	79.75	**55.18**	79.88

(1) Converted from $/GJ using a standard energy conversion rate of 1.06 GJ:1 Mcf.
(2) Before risk management contracts; supplementary financial measure. See "Non-GAAP and Other Financial Measures".

Rubellite’s oil and natural gas revenue for the three and nine months ended September 30, 2025 increased by $14.6 million or 33% and $76.1 million or 70% from the comparative periods of 2024, primarily driven by the increase in sales volumes partially offset by lower oil prices.

Oil revenue for the third quarter of 2025 of $55.5 million represented 95% of total revenue while conventional heavy crude oil production was 69% of total sales volumes. The 27% increase in oil revenue was driven by the 40% increase in heavy crude oil production, partially offset by a 9% decrease in average realized oil prices. Compared to the third quarter of 2024, the WCS average price decreased to $75.10/bbl (Q3 2024 - $83.95/bbl), attributable to the 14% decrease in WTI oil prices, partially offset by an increase in the CAD$/US$ rate to $1.38 (Q3 2024 - $1.36) and a narrowing of the WCS differential to US$10.39/bbl (Q3 2024 - US$13.55/bbl).

During the first nine months of 2025, oil revenue was $170.6 million and represented 92% of total revenue while conventional heavy crude oil production was 69% of total sales volumes. The 56% increase in oil revenue was driven by the 69% increase in heavy crude oil production, partially offset by a 7% decrease in average realized oil prices. Relative to the comparative period of 2024, the WCS average price decreased 8% to $77.88/bbl (2024 - $84.45/bbl) driven by a 14% decrease in WTI oil prices to US$66.70/bbl (2024 - US$77.54/bbl), partially offset by an increase in the CAD$/US$ rate to $1.40 (2024 - $1.36) and the narrowing of the WCS differential to US$11.11/bbl (2024 - US$15.49/bbl).

Rubellite's realized oil price reflects a price offset for quality and optimization of sales delivery points, which averaged $2.70/bbl and $3.82/bbl for the three and nine months ended September 30, 2025 as compared to $4.20/bbl and $4.57/bbl in the comparative periods of 2024.

Natural gas revenue of $1.3 million in the third quarter of 2025 represented 2% of total revenue while natural gas production was 29% of total sales volumes. Natural gas revenues reflected AECO Daily Index prices of $0.63/Mcf. For the nine months ended September 30, 2025, natural gas revenue was $9.2 million and 5% of total revenue while natural gas production was 29% of total sales volumes, reflecting AECO Daily Index prices of $1.50/Mcf.

NGL revenue of $1.5 million in the third quarter of 2025 represented 3% of total revenue and total sales volumes. For the nine months ended September 30, 2025, NGL revenue of $5.7 million represented 3% of total revenue and total sales volumes.

Risk Management Contracts

The Company uses “average realized prices after risk management contracts” which is not a standardized measure, and therefore may not be comparable with the calculation of similar measures by other entities. The measure is used by management to calculate Rubellite’s net realized price, taking into account the monthly settlements of financial crude oil and natural gas forward sales, differentials and foreign exchange contracts. These contracts are put in place to protect Rubellite’s adjusted funds flow from potential downside risk and volatility and to lock in economics on drilling programs and acquisitions.

The following table details realized and unrealized gains and losses on risk management contracts:

	Three months ended September 30,		Nine months ended September 30,	
($ thousands, except as noted)	**2025**	2024	**2025**	2024
Unrealized gain (loss) on risk management contracts				
Unrealized gain (loss) on oil contracts(2)	**(5,446)**	11,418	**2,186**	1,096
Unrealized loss on natural gas contracts	**(1,998)**	—	**(5,218)**	—
Unrealized gain (loss) on risk management contracts	**(7,444)**	11,418	**(3,032)**	1,096
Realized gain (loss) on risk management contracts				
Realized gain (loss) on oil contracts(2)	**1,817**	168	**2,734**	(578)
Realized gain on natural gas contracts	**2,149**	—	**5,867**	—
Realized gain (loss) on risk management contracts	**3,966**	168	**8,601**	(578)

(1) Supplementary financial measure. See "Non-GAAP and Other Financial Measures".
(2) Includes gain (loss) on CAD/USD foreign exchange risk management contracts.

The following table calculates average realized prices after risk management contracts, which is not a standardized measure:

	Three months ended September 30,		Nine months ended September 30,	
	2025	2024	**2025**	2024
Realized gain (loss) on risk management contracts				
Realized gain (loss) on oil contracts ($/bbl)(2)	**2.37**	0.31	**1.19**	(0.42)
Realized gain on natural gas contracts ($/Mcf)	**1.11**	—	**1.01**	—
Realized gain (loss) on risk management contracts ($/boe)	**3.56**	0.31	**2.56**	(0.42)
Average realized prices after risk management contracts(1)				
Oil ($/bbl)(2)	**74.77**	80.06	**75.25**	79.46
Natural gas ($/Mcf)	**1.77**	—	**2.59**	—
NGL ($/bbl)	**56.12**	—	**60.85**	—
Average realized price ($/boe)(1)	**55.83**	80.06	**57.74**	79.46

(1) Supplementary financial measure. See "Non-GAAP and Other Financial Measures".
(2) Includes CAD/USD foreign exchange risk management contracts.

The realized gain on risk management contracts totaled $4.0 million or $3.56/boe for the third quarter of 2025, compared to a gain of $0.2 million or $0.31/boe for the third quarter of 2024. For the nine month period ending September 30, 2025, the realized gain on risk management contracts totaled $8.6 million or $2.56/boe (2024 - realized loss of $0.6 million or $0.42/boe). Hedging gains or losses are attributable to reference price fluctuations relative to pricing on commodity contracts driven by changes in AECO, WTI and WCS differential benchmark prices as well as fluctuations in foreign exchange rates and the percentage of production volumes hedged at any given time.

The unrealized loss on risk management contracts was $7.4 million for the third quarter of 2025 (Q3 2024 – $11.4 million unrealized gain) and the unrealized loss on risk management contracts was $3.0 million for the nine month period ended September 30, 2025 (2024 - $1.1 million unrealized gain). Unrealized gains and losses represent the change in the mark-to-market value of risk management contracts for future periods as forward commodity prices and foreign exchange rates change. Unrealized gains and losses on risk management contracts are excluded from the Company's calculation of cash flow from operating activities as non-cash items. Risk management contract gains and losses vary depending on commodity prices and the nature and extent of the risk management contracts in place, which in turn, vary with the Company's assessment of commodity price risk, committed capital spending and other factors.

Royalties

	Three months ended September 30,		Nine months ended September 30,	
($ thousands, except as noted)	**2025**	2024	**2025**	2024
Royalty expenses	**8,003**	5,259	**25,083**	12,529
$/boe	**7.18**	9.60	**7.46**	9.16
Royalties *(% of revenue)(1)*	**13.7**	12.0	**13.5**	11.5

(1) Non-GAAP ratio. See "Non-GAAP and Other Financial Measures".

Rubellite's royalties consist of Crown royalties payable to the Alberta provincial government, royalties payable to Indian Oil and Gas Canada ("IOGC"), and other freehold and GORR royalties. The mix between Crown, IOGC and freehold production as a percentage of total production can change the composition of royalties from one period to the next. Under the Alberta Modernized Royalty Framework ("MRF"), the Company pays a Crown royalty of between 5% and 20% on wells where mineral rights are leased from the Crown. Under the Indian Oil and Gas Act, the Company pays a royalty of between 10% and 40% on wells where mineral rights are leased. The remainder of royalties are attributable to the composition of freehold and GORR royalties, some of which are price sensitive.

Total royalties for the three and nine months ended September 30, 2025, were $8.0 million and $25.1 million, an increase from the comparative periods of 2024 on higher production, increased revenue and a higher percentage of wells with gross overriding royalties ("GORR").

On a per boe basis, royalties were $7.18/boe and $7.46/boe, a decrease from the comparative periods of 2024 as a result of higher sales volumes and lower prices, which more than offset the higher percentage of wells drilled on lands with a GORR. Royalties as a percentage of revenue were higher than the comparative periods of 2024 due to increased number of wells receiving higher GORR royalty rates.

Net operating costs[1]

	Three months ended September 30,		Nine months ended September 30,	
($ thousands, except as noted)	**2025**	2024	**2025**	2024
Net operating costs	**7,206**	4,634	**22,593**	9,978
$/boe	**6.46**	8.46	**6.72**	7.29

(1) Non-GAAP measure. See "Non-GAAP and Other Financial Measures".

Total net operating costs for the three and nine months ended September 30, 2025 increased to $7.2 million and $22.6 million from $4.6 million and $10.0 million in the comparative periods of 2024 as a result of increased production volumes.

On a per boe basis, net operating costs for the three and nine months decreased by 24% to $6.46/boe and 8% to $6.72/boe (Q3 2024 - $8.46/boe; 2024 - $7.29/boe). During the third quarter of 2025, costs were lower due to a reduction in carbon taxes driven by legislative changes announced in early 2025 and operational efficiencies at the Frog Lake property acquired in the third quarter of 2024. For the nine month period ended September 30, 2025, the reduction was driven by lower well servicing costs and third party processing fees, partially offset by higher repairs and maintenance costs in all areas.

Transportation costs

	Three months ended September 30,		Nine months ended September 30,	
($ thousands, except as noted)	**2025**	2024	**2025**	2024
Transportation costs	**5,201**	4,202	**18,139**	10,581
$/boe	**4.66**	7.67	**5.40**	7.73

Transportation costs include clean oil trucking costs and NGL transportation, as well as costs to transport natural gas from the plant gate to commercial sales point. Costs for the three and nine months ended September 30, 2025 increased to $5.2 million and $18.1 million, up from $4.2 million and $10.6 million in the comparative periods of 2024 as a result of higher volumes.

On a per boe basis, transportation costs of $4.66/boe were 39% lower than the third quarter of 2024 (Q3 2024 - $7.67/boe) and 30% lower during the first nine months of 2025 (2024 - $7.73/boe). The decrease related to improved trucking rates realized for the Company's Clearwater and Frog Lake assets and the addition of natural gas volumes which incur lower transportation costs relative to the heavy oil assets.

Operating netbacks

The following tables highlight Rubellite's operating netbacks for the three and nine months ended September 30, 2025 and 2024**:**

	Three months ended September 30, 2025			Three months ended September 30, 2024		
($ thousands)	**Eastern Heavy Oil**	**West Central**	**Total**	Eastern Heavy Oil	West Central	Total
Revenue	**55,774**	**2,516**	**58,290**	43,682	—	43,682
Royalties	**(7,219)**	**(784)**	**(8,003)**	(5,259)	—	(5,259)
Net operating costs[1]	**(5,406)**	**(1,800)**	**(7,206)**	(4,634)	—	(4,634)
Transportation costs	**(4,529)**	**(672)**	**(5,201)**	(4,202)	—	(4,202)
Operating netback[1]	**38,620**	**(740)**	**37,880**	29,587	—	29,587
Realized gain on risk management contracts[2]	**—**	**—**	**3,966**	—	—	168
Total operating netback, after risk management contracts[1]	**38,620**	**(740)**	**41,846**	29,587	—	29,755

(1) Non-GAAP measure. See "Non-GAAP and Other Financial Measures".
(2) Realized hedging in the third quarter of 2025 is comprised of a $1.8 million gain on oil contracts and a $2.1 million gain on gas contracts (Q3 2024 - $0.2 million gain on oil contracts and nil on gas contracts).

	Nine months ended September 30, 2025			Nine months ended September 30, 2024		
($ thousands)	**Eastern Heavy Oil**	**West Central**	**Total**	Eastern Heavy Oil	West Central	Total
Revenue	**171,819**	**13,620**	**185,439**	109,303	—	109,303
Royalties	**(23,008)**	**(2,075)**	**(25,083)**	(12,529)	—	(12,529)
Net operating costs[1]	**(17,192)**	**(5,401)**	**(22,593)**	(9,978)	—	(9,978)
Transportation costs	**(16,298)**	**(1,841)**	**(18,139)**	(10,581)	—	(10,581)
Operating netback[1]	**115,321**	**4,303**	**119,624**	76,215	—	76,215
Realized gain (loss) on risk management contracts[2]	**—**	**—**	**8,601**	—	—	(578)
Total operating netback, after risk management contracts[1]	**115,321**	**4,303**	**128,225**	76,215	—	75,637

(1) Non-GAAP measure. See "Non-GAAP and Other Financial Measures".
(2) Realized hedging for the first nine months of 2025 is comprised of a $2.7 million gain on oil contracts and a $5.9 million gain on gas contracts (2024 - $0.6 million loss on oil contracts and nil on gas contracts).

($/boe)	Three months ended September 30, 2025 Eastern Heavy Oil	West Central	Total	Three months ended September 30, 2024 Eastern Heavy Oil	West Central	Total
Revenue	**68.65**	**8.31**	**52.27**	79.75	—	79.75
Royalties	**(8.89)**	**(2.59)**	**(7.18)**	(9.60)	—	(9.60)
Net operating costs[1]	**(6.65)**	**(5.94)**	**(6.46)**	(8.46)	—	(8.46)
Transportation costs	**(5.57)**	**(2.22)**	**(4.66)**	(7.67)	—	(7.67)
Operating netback[1]	**47.54**	**(2.44)**	**33.97**	54.02	—	54.02
Realized gain on risk management contracts[2]	**—**	**—**	**3.56**	—	—	0.31
Total operating netback, after risk management contracts[1]	**47.54**	**(2.44)**	**37.53**	54.02	—	54.33

(1) Non-GAAP measure. See "Non-GAAP and Other Financial Measures".
(2) Realized hedging in the third quarter of 2025 is comprised of a $2.37/bbl gain on oil contracts and a $1.11/Mcf gain on gas contracts (2024 - $0.31/bbl gain on oil contracts and nil on gas contracts).

($/boe)	Nine months ended September 30, 2025 Eastern Heavy Oil	West Central	Total	Nine months ended September 30, 2024 Eastern Heavy Oil	West Central	Total
Revenue	**70.81**	**14.58**	**55.18**	79.88	—	79.88
Royalties	**(9.48)**	**(2.22)**	**(7.46)**	(9.16)	—	(9.16)
Net operating costs[1]	**(6.94)**	**(5.78)**	**(6.72)**	(7.29)	—	(7.29)
Transportation costs	**(6.72)**	**(1.97)**	**(5.40)**	(7.73)	—	(7.73)
Operating netback[1]	**47.67**	**4.61**	**35.60**	55.70	—	55.70
Realized gain (loss) on risk management contracts[2]	**—**	**—**	**2.56**	—	—	(0.42)
Total operating netback, after risk management contracts[1]	**47.67**	**4.61**	**38.16**	55.70	—	55.28

(1) Non-GAAP measure. See "Non-GAAP and Other Financial Measures".
(2) Realized hedging for the first nine months of 2025 is comprised of a $1.19/bbl gain on oil contracts and a $1.01/Mcf gain on gas contracts (2024 - $0.42/bbl loss on oil contracts and nil on gas contracts).

Rubellite's Eastern Heavy Oil operating netback for the three and nine months ended September 30, 2025 increased to $38.6 million and $115.3 million (Q3 2024 - $29.6 million; 2024 - $76.2 million) as a result of higher sales volumes. On a per boe basis, the decrease during the three and nine months ended September 30, 2025 relative to the comparable periods of 2024 was driven by lower realized oil prices, partially offset by lower royalties and net operating and transportation costs.

Rubellite's total operating netback for the three and nine months ended September 30, 2025 increased to $37.9 million and $119.6 million from $29.6 million and $76.2 million in the comparative periods of 2024. On a per boe basis, the decrease was driven by lower total realized prices, reflecting lower oil prices and the addition of natural gas to the sales product mix through the Recombination Transaction and the completion of the Figure Lake gas plant, partially offset by reduced royalties and net operating and transportation costs.

For the three and nine month ended September 30, 2025, the operating netback after a realized gain on risk management contracts was $37.53/boe and $38.16/boe (Q3 2024 – $54.33/boe; 2024 - $55.28/boe).

General and administrative (“G&A”) expenses

($ thousands, except as noted)	Three months ended September 30, 2025	2024	Nine months ended September 30, 2025	2024
G&A expenses – before MSA costs & recoveries	**5,220**	1,048	**15,947**	2,594
G&A recoveries	**(1,605)**	—	**(3,903)**	—
MSA costs[1]	**—**	1,620	**—**	4,500
Total G&A expenses	**3,615**	2,668	**12,044**	7,094
$/boe	**3.24**	4.87	**3.58**	5.18

(1) Prior to the Recombination Transaction, Rubellite Energy Inc. and Perpetual were considered related parties due to the existence of a Management and Operating Services Agreement ("MSA") and certain officers and directors being key management of, and having significant influence over, Rubellite Energy Inc. while also being key management of and having deemed control over Perpetual. Under the MSA, Rubellite Energy Inc. made payments to Perpetual for certain technical, capital and administrative services provided to Rubellite Energy Inc. on a relative cost sharing basis.

G&A expenses for the three and nine months ended September 30, 2025 increased to $5.2 million and $15.9 million (Q3 2024 – $1.0 million; 2024 - $2.6 million). Prior to the Recombination Transaction, G&A expenses, excluding MSA costs, consisted primarily of legal fees, computer software licenses, insurance, professional fees and public company costs. After the Recombination Transaction was completed, G&A expenses in Rubellite increased to include all G&A costs previously billed through the MSA including people, office and computer costs and recoveries.

For the three and nine months ended September 30, 2025, G&A costs on a per boe basis decreased to $3.24/boe and $3.58/boe from $4.87/boe and $5.18/boe in the comparative periods of 2024 due to higher sales volumes.

Depletion

	Three months ended September 30,		Nine months ended September 30,	
(*$ thousands, except as noted*)	**2025**	2024	**2025**	2024
Depletion	**23,093**	13,047	**68,420**	30,546
Depreciation	**521**	71	**1,530**	213
Total depletion and depreciation	**23,614**	13,118	**69,950**	30,759
($/boe)				
Depletion	**20.71**	23.82	**20.36**	22.32
Depreciation	**0.47**	0.13	**0.46**	0.16
$/boe	**21.18**	23.95	**20.82**	22.48

The Company calculates depletion using the net book value of the asset, future development costs associated with proved and probable reserves, salvage values on associated production equipment, as well as proved plus probable reserves. As at September 30, 2025, depletion was calculated on a $496.4 million depletable balance (December 31, 2024 – $473.4 million), $387.5 million in future development costs (December 31, 2024 – $436.3 million) and excluded an estimated $9.2 million of salvage value (December 31, 2024 – $8.7 million).

Depletion and depreciation expense for the third quarter of 2025 was $23.6 million or $21.18/boe (Q3 2024 – $13.1 million or $23.95/boe). For the first nine months of 2025, depletion and depreciation expense was $70.0 million or $20.82/boe (2024 - $30.8 or $22.48/boe). The increase in depletion related to a higher depletable base than the comparable period as a result of the BMEC Acquisition and the Recombination Transaction. On a per boe basis, depletion was lower in the three and nine months ended September 30, 2025 relative to the comparable periods of 2024, as a result of the Recombination Transaction, as the West Central assets have higher reserves relative to production resulting in a lower per unit cost of reserves relative to Rubellite's Eastern Heavy Oil assets. Depletion will fluctuate from one period to the next depending on the amount of capital spent, the amount of reserves added and volumes produced.

Impairment

There were no indicators of impairment for either of the Company's CGUs as at September 30, 2025, therefore, an impairment test was not performed.

E&E assets are tested for impairment when internal or external indicators of impairment exist as well as upon reclassification to oil and natural gas interests in PP&E. At September 30, 2025, the Company conducted an assessment of indicators of impairment for the Company's E&E assets. In performing the assessment, management determined there were no indicators of impairment.

During the first nine months of 2025 there have been no transfers between E&E and PP&E. During 2024, the Company transferred $20.8 million of E&E to PP&E. As a result of the transfer, the Company performed the required impairment test to estimate the recoverable amount of the CGU. It was determined that the recoverable amount of the CGU exceeded its carrying value, resulting in no impairment.

Finance expense

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	**2025**	2024	**2025**	2024
Cash finance expense				
Interest on bank debt	**1,909**	1,663	**5,406**	3,750
Interest on Term Loan	**580**	372	**1,721**	372
Interest on lease liabilities	**79**	—	**239**	—
Total cash finance expense	**2,568**	2,035	**7,366**	4,122
$/boe	**2.30**	3.72	**2.19**	3.02
Non-cash finance expense				
Amortization of debt issue costs	**44**	24	**126**	24
Accretion on decommissioning obligations	**282**	75	**811**	208
Accretion on other provision	**114**	—	**366**	—
Total non-cash finance expense	**440**	99	**1,303**	232
$/boe	**0.39**	0.18	**0.39**	0.17
Finance expense	**3,008**	2,134	**8,669**	4,354

Total cash finance expense for the three and nine months ended September 30, 2025 increased to $2.6 million and $7.4 million (Q3 2024 - $2.0 million; 2024 - $4.1 million) as a result of higher average outstanding bank debt during the period, the addition of the term loan in the third quarter of 2024 and interest on lease liabilities from the Recombination Transaction. The effective aggregate interest rate on the Company's bank line for both the three and nine month period ended September 30, 2025 was 6.2% (Q3 2024 - 8.6%; 2024 - 8.5%) and the interest rate on the term loan was 11.5%.

Non-cash finance expense represents accretion on decommissioning obligations, accretion on the other provision and amortization of debt issue costs.

For the three and nine months ended September 30, 2025, cash finance expense on a per boe basis decreased from the comparative periods of 2024 due to higher sales volumes.

Deferred Income Taxes

($ thousands)	December 31, 2024	Recognized in earnings	Recognized in equity	**September 30, 2025**
Assets (liabilities):				
Property, plant and equipment	(30,903)	(4,627)	—	**(35,530)**
Decommissioning obligations	7,318	149	—	**7,467**
Fair value of derivatives	(1,661)	697	—	**(964)**
Other provision and liabilities	4,049	(1,315)	—	**2,734**
Share and debt issue costs	669	(56)	(129)	**484**
Non-capital losses	41,965	(4,309)	—	**37,656**
Total deferred tax assets	21,437	(9,461)	(129)	**11,847**

For the three and nine months ended September 30, 2025, the Company recorded a deferred income tax expense of $1.8 million and $9.5 million (Q3 2024 - income tax expense of $5.4 million; 2024 - income tax expense of $6.8 million).

LIQUIDITY, CAPITALIZATION AND FINANCIAL RESOURCES

Rubellite's strategy targets the maintenance of a strong capital base to retain investor, creditor and market confidence to support the execution of its business plans. The Company manages its capital structure and adjusts its capital spending in light of changes in economic conditions, available liquidity, and the risk characteristics of its underlying assets. The Company considers its capital structure to include share capital, bank debt, term loans and adjusted working capital. To manage its capital structure and available liquidity, Rubellite may from time to time issue equity or debt securities, sell assets, and adjust its capital spending to manage current and projected debt levels. The Company will continue to regularly assess changes to its capital structure, with considerations for both short-term liquidity and long-term financial sustainability.

Capital Management

($ thousands, except as noted)	**September 30, 2025**	December 31, 2024
Bank debt(1)	**90,639**	105,945
Term Loan (principal)	**20,000**	20,000
Adjusted working capital deficit(1)(2)	**27,715**	28,075
Net debt(2)	**138,354**	154,020
Shares outstanding at end of period (*thousands*)	**93,670**	93,044
Market price at end of period (*$/share*)	**2.26**	2.12
Market value of shares(2)	**211,694**	197,253
Enterprise value(2)	**350,048**	351,273
Net debt as a percentage of enterprise value(2)	**40%**	44%
Trailing twelve months adjusted funds flow(2)	**140,540**	93,777
Net debt to trailing twelve months adjusted funds flow ratio(2)	**1.0**	1.6
Q3 annualized adjusted funds flow(2)(3)	**142,652**	100,156
Net debt to Q3 annualized adjusted funds flow ratio(2)(3)	**1.0**	1.5

(1) Bank debt shown net of cash balance of $2.6 million as at December 31, 2024. Adjusted working capital deficit excludes the cash balance of $2.6 million as at December 31, 2024.
(2) Non-GAAP measure or ratio. See "Non-GAAP and Other Financial Measures".
(3) Based on Q3 2025 adjusted funds flow, before transaction costs of $35.7 million (Q3 2024 - $25.0 million). See "Non-GAAP and Other Financial Measures" for more details.

At September 30, 2025, Rubellite had net debt of $138.4 million, a 10% decrease from $154.0 million at December 31, 2024. Net debt decreased as a result of adjusted funds flow for the first nine months of 2025 of $108.9 million exceeding capital expenditures including land and other expenditures of $91.5 million, which generated free funds flow $17.4 million and proceeds of $5.5 million from the sale of undeveloped land during the third quarter. The positive free funds flow and proceeds from the undeveloped land disposition were primarily used to reduce net debt and other obligations which included the $3.8 million reduction of the other provision, $1.3 million of spending on decommissioning activities and $2.6 million in payments for cash-settled share-based compensation.

Rubellite had available liquidity at September 30, 2025 of $48.0 million, comprised of the $140.0 million Credit Facility Borrowing Limit, less bank borrowings of $90.6 million and outstanding letters of credit of $1.4 million.

Bank debt

As at September 30, 2025, the Company's first lien credit facility had a borrowing limit of $140.0 million (December 31, 2024 - $140.0 million). The initial term is to May 31, 2026 and may be extended for a further twelve months to May 31, 2027 subject to lender approval. If not extended by May 31, 2026, all outstanding advances would be repayable on May 31, 2027. The next semi-annual borrowing base redetermination is scheduled on or before November 30, 2025.

As at September 30, 2025, $90.6 million was drawn against the credit facility (December 31, 2024 - $108.5 million) and $1.4 million (December 31, 2024 - $3.6 million) of letters of credit have been issued. Borrowings under the credit facility bear interest at the lenders' prime rate or CORRA rates, plus applicable margins and standby fees. The applicable CORRA margins range between 2.8% and 6.3%. The effective aggregate interest rate on the credit facility at September 30, 2025 was 6.2% per annum. For the period ended September 30, 2025, if interest rates changed by 1% with all other variables held constant, the impact on cash finance expense and net income and comprehensive income would be $0.7 million.

The credit facility is secured by general first lien security agreements covering all present and future property of the Company.

At September 30, 2025, the credit facility was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Term Loan

			September 30, 2025		December 31, 2024	
($ thousands)	**Maturity date**	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
Term loan	August 2, 2029	11.5%	**20,000**	**19,128**	20,000	19,027

On August 2, 2024, Rubellite entered into a senior secured second-lien term loan which was placed, directly or indirectly, with certain directors and officers, and their affiliates, of Rubellite and the Company's significant shareholder for $20.0 million. The term loan bears interest at 11.5% annually with interest payments to be paid quarterly and matures in five years from the date of issue, and can be repaid by the Company without penalty at any time. In conjunction with the closing of the Recombination Transaction, the term loan was converted to a third-lien obligation of the Company.

During the three and nine months ending September 30, 2025, Rubellite paid $0.6 and $1.7 million in cash interest payments to the holders of the term loan (three and nine months ended September 30, 2024 - $0.4 million).

At September 30, 2025, the term loan has been recorded at the present value of future cash flows, net of $0.9 million (December 31, 2024 - $1.0 million) in issue and discount costs which are amortized over the remaining term using a weighted average effective interest rate of 13.0%.

The term loan is not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

At September 30, 2025, entities controlled or directed by the Company's Chief Executive Officer ("CEO") hold $18.4 million of the outstanding term loan.

Equity

At September 30, 2025, there were 93.6 million common shares outstanding, net of 0.1 million shares held in trust for employee compensation programs (December 31, 2024 - 92.9 million common shares outstanding, net of 0.2 million of shares held in trust).

On August 2, 2024, in conjunction with the closing of the BMEC Acquisition, Rubellite issued 5.0 million common shares to certain shareholders of Buffalo Mission, which were valued at $10.4 million using the Company's share price on the closing date of the transaction of $2.07 per share.

On October 31, 2024, in conjunction with the closing of the Recombination Transaction, Rubellite issued 25.4 million common shares which were valued at $51.7 million using the Company's share price on the closing date of the transaction of $2.04 per share.

At November 5, 2025 there were 93.6 million common shares outstanding, net of 0.1 million shares held in trust for employee compensation programs.

The following table summarizes information about options and performance awards and restricted awards outstanding as the date of this MD&A:

(thousands)	**November 5, 2025**
Restricted share units	3,379
Share options	2,977
Performance share units	1,944
Perpetual awards(1)(2)	2,347
Total	**10,647**

(1) Perpetual awards from the Recombination Transaction include 0.9 million deferred options, 0.3 million deferred shares, 0.8 million share options and 0.3 million performance share rights. All Perpetual awards from the Recombination Transaction were adjusted both in number issued and exercise price by the exchange ratio of 5:1.

(2) Total awards outstanding include 1.4 million legacy awards that can be settled for cash or from shares in the trust as opposed to treasury. Shares in the trust as at November 5, 2025 0.8 million.

Commodity price risk management

As at November 5, 2025, Rubellite had entered into the following oil commodity risk management contracts:

Commodity	**Volumes Sold (bbl/d)**	**Term**	**Reference/Index**	**Contract Traded Bought/Sold**	**Average Price ($/bbl)**
Crude Oil	1,900 bbl/d	Oct 2025 - Dec 2025	WTI (US$/bbl)	Swap - sold	$67.15
Crude Oil	1,500 bbl/d	Jan 2026 - Mar 2026	WTI (US$/bbl)	Swap - sold	$65.13
Crude Oil	500 bbl/d	Apr 2026 - Dec 2026	WTI (US$/bbl)	Swap - sold	$65.00
Crude Oil	250 bbl/d	Nov 2025 - Dec 2025	WTI (CAD$/bbl)	Swap - sold	$90.03
Crude Oil	2,900 bbl/d	Oct 2025 - Dec 2025	WCS Differential (US$/bbl)	Swap - sold	($13.60)
Crude Oil	1,000 bbl/d	Jan 2026 - Dec 2026	WCS Differential (US$/bbl)	Swap - sold	($12.50)
Crude Oil	250 bbl/d	Nov 2025 - Dec 2025	WCS Differential (CAD$/bbl)	Swap - sold	($16.28)
Crude Oil	200 bbl/d	Oct 2025	WCS (CAD$/bbl)	Swap - sold	$80.00
Crude Oil	950 bbl/d	Nov 2025 - Dec 2025	WCS (CAD$/bbl)	Swap - sold	$74.47

As at November 5, 2025, Rubellite had entered into the following natural gas commodity risk management contracts:

Commodity	Volumes Sold	Term	Reference/Index	Contract Traded Bought/Sold	Average Price ($/GJ)
Natural gas(1)	2,500 GJ/d	Oct 2025	AECO 5A (CAD$/GJ)	Swap - sold	$9.01

(1) Inclusive of 15,000 GJ/d sold at $3.19/GJ and a $5.82/GJ realized gain on 12,500 GJ/d of contracted volumes closed out during the period.

Foreign exchange risk management

As at November 5, 2025, Rubellite entered into the following foreign exchange risk management contracts:

Fixed Contract	Notional amount	Term	Price (CAD$/US$)
Average rate forward (CAD$/US$)	$2,050,000 US$/month	Oct - Dec 2025	1.3763
Average rate forward (CAD$/US$)	$2,500,000 US$/month	Jan - Dec 2026	1.4066
Average rate forward (CAD$/US$)	$5,000,000 US$/month	Jan - Dec 2026	1.3890

(1) At expiry on December 31, 2026 if the calendar 2027 forward strip is above 1.3890 CAD$/US$, Rubellite knocks into a $5.0 million US$/month contract at 1.3890 CAD$/US$ for the 2027 calendar year.

Variable Contract(1)	Notional amount	Term	Floor Price (CAD$/US$)	Ceiling Price (CAD$/US$)	Reset Price (CAD$/US$)
Knock-in Collar (CAD$/US$)	$500,000 US$/month	Oct - Dec 2025	1.3700	1.4375	1.3875
Knock-in Collar (CAD$/US$)	$500,000 US$/month	Oct - Dec 2025	1.3700	1.4300	1.4000

(1) If the monthly average exchange rate is below the floor price, settlement for that month will occur at the floor price. If the monthly average exchange rate is above the ceiling price, settlement for that month will be against the reset price. No settlement occurs when the monthly average exchange rate is between the floor and ceiling price.

COMMITMENTS AND CONTRACTUAL OBLIGATIONS

The Company has a drilling commitment on certain GORR lands that must be fulfilled by June 30, 2026 (the "Commitment Date"). In the event the Company fails to fulfill the drilling commitment, the Company is required to pay $0.1 million per well not spud by the Commitment Date. As at September 30, 2025, the Company has drilled 24 gross (24.0 net) of the 59 gross (59.0 net) wells that are required to meet the drilling commitment. Subsequent to September 30, 2025, the Company has drilled an additional 3 gross (3.0 net) wells for a total of 27 gross (27.0 net) wells required to meet the drilling commitment.

PROVISIONS

Decommissioning obligations

Decommissioning obligations are estimated based on the Company’s net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities, and the estimated timing of the costs to be incurred in future periods.

The increase in the provision due to the passage of time, which is referred to as accretion, is recognized as non-cash finance expense in the consolidated statements of income and comprehensive income. Decommissioning obligations are further adjusted at each period end date for changes in the risk-free interest rate, after considering additions and dispositions of PP&E. Decommissioning obligations are also adjusted for revisions to future cost estimates and the estimated timing of costs to be incurred in future periods.

($ thousands)	**September 30, 2025**	December 31, 2024
Decommissioning obligations – current	**1,415**	2,000
Decommissioning obligations – non-current	**31,051**	29,817
Total decommissioning obligations	**32,466**	31,817

The following significant assumptions were used to estimate the Company’s decommissioning obligations:

(*$ thousands, except as noted*)	**September 30, 2025**	December 31, 2024
Undiscounted obligations	**43,596**	42,085
Average risk-free rate	**3.6%**	3.3%
Inflation rate	**2.0%**	1.8%
Expected timing of settling obligations	**1 to 25 years**	1 to 25 years

Other provision

The other provision was assumed as part of the Recombination Transaction and relates to a "Settlement Agreement" Perpetual entered into to resolve litigation by providing amounts to settle asset retirement obligations without any party admitting liability, wrongdoing or violation of laws, regulations, public policy or fiduciary duties. The Company will make annual installment payments of $3.75 million until the total amount of the Settlement Principal is paid. The annual scheduled payment was made on March 28, 2025 and all scheduled payments made prior to March 28, 2026 will have the interest forgiven. As of March 28, 2026, interest will accrue and be payable on the outstanding Settlement Principal annually at an interest rate equal to the applicable Bank of Canada prime rate on the date of payment. The Company is able to pre-pay all, or any portion, of the outstanding balance of the Settlement Principal at any time without bonus or penalty.

($ thousands)	**September 30, 2025**	December 31, 2024
Other provisions – current	**3,750**	3,750
Other provisions – non-current	**11,440**	14,824
Total other provisions	**15,190**	18,574

The following assumptions were used to estimate the other provision:

(*$ thousands, except as noted*)	**September 30, 2025**	December 31, 2024
Undiscounted obligations	**16,191**	19,941
Average risk-free rate	**3.0%**	3.0%
Expected timing of settling obligations	**4.5 years**	5.3 years

OFF BALANCE SHEET ARRANGEMENTS

Rubellite has no material off balance sheet arrangements.

NON-GAAP AND OTHER FINANCIAL MEASURES

Throughout this MD&A and in other materials disclosed by the Company, Rubellite employs certain measures to analyze financial performance, financial position and cash flow. These non-GAAP and other financial measures do not have any standardized meaning prescribed under IFRS and therefore may not be comparable to similar measures presented by other entities. The non-GAAP and other financial measures should not be considered to be more meaningful than GAAP measures which are determined in accordance with IFRS, such as net income (loss), cash flow from (used in) operating activities, and cash flow from (used in) investing activities, as indicators of Rubellite's performance.

Non-GAAP Financial Measures

Capital Expenditures: Rubellite uses capital expenditures related to exploration and development to measure its capital investments compared to the Company's annual capital budgeted expenditures. Rubellite's capital budget excludes acquisition and disposition activities.

The most directly comparable GAAP measure for capital expenditures is cash flow used in investing activities. A summary of the reconciliation of cash flow used in investing activities to capital expenditures, is set forth below:

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	**2025**	2024	**2025**	2024
Net cash flows used in investing activities	**(19,291)**	(86,044)	**(82,304)**	(123,397)
Acquisitions	**—**	(62,732)	**—**	(62,732)
Dispositions	**5,500**	—	**5,500**	—
Change in non-cash working capital	**10,574**	13,338	**3,661**	12,704
Capital expenditures, including land and other	**(35,365)**	(36,650)	**(91,465)**	(73,369)
Property, plant and equipment additions	**(34,854)**	(28,348)	**(84,407)**	(58,115)
Exploration and evaluation additions	**(312)**	(8,250)	**(6,662)**	(12,285)
Corporate additions	**(199)**	(52)	**(396)**	(2,969)
Capital expenditures, including land and other	**(35,365)**	(36,650)	**(91,465)**	(73,369)

Cash costs: Cash costs are comprised of net operating costs, transportation, general and administrative, and cash finance expense as detailed below. Cash costs per boe is calculated by dividing cash costs by total production sold in the period. Management believes that cash costs assist management and investors in assessing Rubellite's efficiency and overall cost structure.

			Three months ended September 30,	
(*$ thousands, except per boe amounts*)	***$/boe***	**2025**	*$/boe*	2024
Net operating costs	**6.46**	**7,206**	8.46	4,634
Transportation	**4.66**	**5,201**	7.67	4,202
General and administrative	**3.24**	**3,615**	4.87	2,668
Cash finance expense	**2.30**	**2,568**	3.72	2,035
Cash costs	**16.66**	**18,590**	24.72	13,539

			Nine Months Ended September 30,	
(*$ thousands, except per boe amounts*)	***$/boe***	**2025**	*$/boe*	2024
Net operating costs	**6.72**	**22,593**	7.29	9,978
Transportation	**5.40**	**18,139**	7.73	10,581
General and administrative	**3.58**	**12,044**	5.18	7,094
Cash finance expense	**2.19**	**7,366**	3.02	4,122
Cash costs	**17.89**	**60,142**	23.22	31,775

Operating netbacks and total operating netbacks, after risk management contracts: Operating netback is calculated by deducting royalties, net operating expenses, and transportation costs from oil and natural gas revenue. Operating netback is also calculated on a per boe basis using total production sold in the period. Total operating netbacks, after risk management contracts, is presented after adjusting for realized gains or losses from risk management contracts. Rubellite considers operating netback and operating netback after risk management contracts to be key industry performance indicators that provides investors with information that is also commonly presented by other oil and natural gas producers. Rubellite presents the operating netback at a CGU level as it provides investors with key information related to the Eastern Heavy Oil CGU which is the area where growth capital investment is focused. Operating netback and operating netback, after risk management contracts, evaluate operational performance as it demonstrates its profitability relative to realized and current commodity prices.

Net operating costs: Net operating costs equals operating expenses net of other income, which is made up of processing revenue and other one time items from time to time. Management views net operating costs as an important measure to evaluate its operational performance. The most directly comparable IFRS measure for net operating costs is production and operating expenses.

The following table reconciles net operating costs from production and operating expenses and other income in the Company's consolidated statement of income (loss) and comprehensive income (loss).

	Three months ended September 30,		Nine months ended September 30,	
(*$ thousands, except per boe amounts*)	**2025**	2024	**2025**	2024
Other income	**75**	—	**580**	—
Less: Non processing income	**—**	—	**(343)**	—
Processing income	**75**	—	**237**	—
Production and operating	**7,281**	4,634	**22,830**	9,978
Less: processing income	**(75)**	—	**(237)**	—
Net operating costs	**7,206**	4,634	**22,593**	9,978
$/boe	**6.46**	8.46	**6.72**	7.29

Refer to reconciliations in the MD&A under the "Operating Netbacks" section for current period and comparative information.

Net Debt and Adjusted Working Capital Deficit: Rubellite uses net debt as an alternative measure of outstanding debt and is calculated by adding borrowings under the credit facility and term loan debt less adjusted working capital. Adjusted working capital is calculated by adding cash, accounts receivable, prepaid expenses and deposits and product inventory less accounts payable and accrued liabilities. Management considers net debt as an important measure in assessing the liquidity of the Company. Net debt is used by management to assess the Company's overall debt position and borrowing capacity. Net debt is not a standardized measure and therefore may not be comparable to similar measures presented by other entities.

The following table reconciles working capital and net debt as reported in the Company's statements of financial position:

(*$ thousands*)	**As of September 30, 2025**	As of December 31, 2024
Current assets	**31,631**	44,714
Current liabilities	**(66,366)**	(74,680)
Working capital deficit	**34,735**	29,966
Risk management contracts – current asset	**4,690**	9,783
Risk management contracts – current liability	**(812)**	(2,765)
Lease liability - current liability	**(387)**	(357)
Share-based compensation liability - current liability	**(5,346)**	(5,357)
Decommissioning obligations – current liability	**(1,415)**	(2,000)
Other provision - current liability	**(3,750)**	(3,750)
Adjusted working capital deficit(1)	**27,715**	25,520
Bank indebtedness	**90,639**	108,500
Term loan (principal)	**20,000**	20,000
Net debt(2)	**138,354**	154,020

(1) Calculation of current assets less current liabilities has been adjusted for the removal of the current portion of risk management contracts, decommissioning liabilities, lease liabilities, share-based compensation and other provisions.
(2) Excludes other non-current liabilities.

Adjusted funds flow: Adjusted funds flow is calculated based on net cash flows from operating activities, excluding changes in non-cash working capital and expenditures on decommissioning obligations, other provisions and share-based compensation since the Company believes the timing of collection, payment or incurrence of these items is variable. Expenditures on decommissioning and share based compensation obligations may vary from period to period and are managed as expenditures through the corporate budgeting process which considers available adjusted funds flow. Management uses adjusted funds flow and adjusted funds flow per boe as key measures to assess the ability of the Company to generate the funds necessary to finance capital expenditures, expenditures on decommissioning obligations, expenditures on share based compensation and meet its financial obligations.

Adjusted funds flow is not intended to represent net cash flows from operating activities calculated in accordance with IFRS.

The following table reconciles net cash flows from operating activities, as reported in the Company's statements of cash flows, to adjusted funds flow:

	Three months ended September 30,		Nine months ended September 30,	
(*$ thousands, except as noted*)	**2025**	2024	**2025**	2024
Net cash flows from operating activities	**34,953**	19,973	**97,896**	56,386
Change in non-cash working capital	**(1,223)**	2,934	**3,352**	5,489
Cash-settled share-based compensation	**1,539**	—	**2,624**	—
Other provision settled	**—**	—	**3,750**	**—**
Decommissioning obligations settled	**394**	122	**1,286**	270
Adjusted funds flow	**35,663**	23,029	**108,908**	62,145
Transaction costs	**—**	2,010	**—**	2,010
Adjusted funds flow, before transaction costs	**35,663**	25,039	**108,908**	64,155
Adjusted funds flow per share - basic	**0.38**	0.35	**1.17**	0.98
Adjusted funds flow per share - diluted	**0.37**	0.35	**1.14**	0.96
Adjusted funds flow per boe	**31.98**	42.04	**32.41**	45.42
Adjusted funds flow per share - before transaction costs - basic	**0.38**	0.37	**1.17**	1.00
Adjusted funds flow per share - before transaction costs - diluted	**0.37**	0.37	**1.14**	0.99
Adjusted funds flow per boe - before transaction costs	**31.98**	45.04	**32.41**	46.62

Free funds flow: Free funds flow is an important measure that informs efficiency of capital spent and liquidity. Free funds flow is calculated as adjusted funds flow generated during the period less capital expenditures. Rubellite's capital expenditures excluded non cash items and acquisitions and dispositions. Adjusted funds flow and capital expenditures are non-GAAP financial measures which have been reconciled to its most directly comparable GAAP measure previously in this document. By removing the impact of current period capital expenditures from adjusted funds flow, Rubellite monitors its free funds flow to inform decisions such as capital allocation and debt repayment.

The following table shows the calculation of the removal of capital expenditures from adjusted funds flows pre transaction costs:

	Three months ended September 30,		Nine months ended September 30,	
(*$ thousands*)	**2025**	2024	**2025**	2024
Adjusted funds flow	**35,663**	23,029	**108,908**	62,145
Capital expenditures, including land and other	**(35,365)**	(36,650)	**(91,465)**	(73,369)
Free funds flow	**298**	(13,621)	**17,443**	(11,224)

Available Liquidity: Available liquidity is defined as the borrowing limit under the Company's credit facility, plus any cash and cash equivalents, less any borrowings and letters of credit issued under the credit facility. Management uses available liquidity to assess the ability of the Company to finance capital expenditures, expenditures on decommissioning obligations and to meet its financial obligations.

Enterprise value: Enterprise value is equal to net debt plus the market value of issued equity, and is used by management to analyze leverage. Enterprise value is calculated by multiplying the current shares outstanding by the market price at the end of the period and then adjusting it by the net debt. The Company considers enterprise value as an important measure as it normalizes the market value of the Company's shares for its capital structure.

Non-GAAP Financial Ratios

Rubellite calculates certain non-GAAP measures per boe as the measure divided by weighted average daily production. Management believes that per boe ratios are a key industry performance measure of operational efficiency and one that provides investors with information that is also commonly presented by other crude oil and natural gas producers. Rubellite also calculates certain non-GAAP measures per share as the measure divided by outstanding common shares, weighted average common shares or diluted weighted average common shares.

Average realized prices after risk management contracts: are calculated as the average realized price by product type less the realized gain or loss on risk management contracts by product type.

Net debt to adjusted funds flow ratio: Net debt to adjusted funds flow ratios are calculated on a trailing twelve-month basis.

Net debt to annualized adjusted funds flow ratio: Net debt to annualized adjusted funds flow ratios are calculated by annualizing the current quarter adjusted funds flow after transaction costs.

Net debt as a percentage of enterprise value: Net debt as a percentage of enterprise value is calculated by dividing net debt by enterprise value.

Adjusted funds flow per share: Adjusted funds flow ratios are calculated on a per share as the measure divided by basic shares outstanding.

Adjusted funds flow per boe: Adjusted funds flow per boe is calculated as adjusted funds flow divided by total production sold in the period.

Supplementary Financial Measures

"Average realized price" is comprised of total oil and natural gas revenue, as determined in accordance with IFRS, divided by the Company's total sales production on a per barrel basis.

"Realized oil price" is comprised of oil commodity sales from production, as determined in accordance with IFRS, divided by the Company's oil sales production.

"Realized natural gas price" is comprised of natural gas commodity sales from production, as determined in accordance with IFRS, divided by the Company's natural gas sales production.

"Realized NGL price" is comprised of NGL commodity sales from production, as determined in accordance with IFRS, divided by the Company's NGL sales production.

"Realized gain (loss) on natural gas contracts per Mcf" is comprised of the realized gain or loss on natural gas contracts, as determined in accordance with IFRS, divided by the Company's total natural gas sales production.

"Realized gain (loss) on oil contracts per boe" is comprised of the realized gain or loss on oil contracts, as determined in accordance with IFRS, divided by the Company's total oil sales production.

"Realized gain (loss) on risk management contracts per boe" is comprised of the realized gain or loss on risk management contracts, as determined in accordance with IFRS, divided by the Company's total sales production.

"Royalties as a percentage of revenue" is comprised of royalties, as determined in accordance with IFRS, divided by oil and natural gas revenue from sales production as determined in accordance with IFRS.

"Royalties per boe" is comprised of royalties, as determined in accordance with IFRS, divided by the Company's total sales production.

"Net operating expense per boe" is comprised of net operating expense, divided by the Company's total sales production.

"Transportation cost ($/boe)" is comprised of transportation cost, as determined in accordance with IFRS, divided by the Company's total sales production.

"G&A cost ($/boe)" is comprised of G&A expense, as determined in accordance with IFRS, divided by the Company's total sales production.

"Depletion and depreciation expense ($/boe)" is comprised of depletion expense, as determined in accordance with IFRS, divided by the Company's total sales production.

“Market value of shares” is comprised of common shares outstanding multiplied by the market price of shares.

“Heavy oil wellhead differential ($/bbl)” represents the differential the Company receives for selling its heavy crude oil production relative to the Western Canadian Select reference price (CAD$/bbl) prior to any price or risk management activities.

INTERNAL CONTROLS AND PROCEDURES

The Company's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures ("DC&P"), as defined by National Instrument 52-109. The Company's CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting ("ICFR"), as defined by National Instrument 52-109, to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with IFRS Accounting Standards.

There were no changes in the Company's DC&P or ICFR during the period beginning July 1, 2025 and ending on September 30, 2025 that have materially affected, or are reasonably likely to materially affect, the Company's ICFR. It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived can provide only reasonable, but not absolute assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

FORWARD-LOOKING INFORMATION

Certain information in this MD&A including management's assessment of future plans and operations, and including the information contained under the headings "Operations Update" and “Outlook and Guidance” may constitute forward-looking information or statements (together "forward-looking information") under applicable securities laws. The forward-looking information includes, without limitation, statements with respect to: future capital expenditures, production and various cost forecasts; the anticipated sources of funds to be used for capital spending; expectations as to future exploration, development and drilling activity, regulatory application and the benefits to be derived from such drilling including production growth; maintaining the one rig drilling program at each of Figure Lake and Frog Lake for the remainder of 2025; the plan to advance strategic initiatives such as land continuation and new capture, secondary recovery and exploration; the ability to obtain meaningful per well capital cost reductions to maintain attractive rates of return and payout periods; the plan to manage capital spending to prioritize free funds flow generation over production growth in the current commodity price environment; the use of excess free funds flow to reduce net debt and for other balance sheet obligations; adjusted funds flow, free funds flow and commodity price forecasts; Rubellite's business plan; and including the forward-looking information contained under the heading "Outlook and Guidance" and "Nature of Business".

Forward-looking information is based on current expectations, estimates and projections that involve a number of known and unknown risks, which could cause actual results to vary and in some instances to differ materially from those anticipated by Rubellite and described in the forward-looking information contained in this MD&A. In particular and without limitation of the foregoing, material factors or assumptions on which the forward-looking information in this MD&A is based include: the successful operation of the Company's assets, forecast commodity prices and other pricing assumptions; forecast production volumes based on business and market conditions; foreign exchange and interest rates; near-term pricing and continued volatility of the market; accounting estimates and judgments; future use and development of technology and associated expected future results; the ability to obtain regulatory approvals; the successful and timely implementation of capital projects; ability to generate sufficient cash flow to meet current and future obligations and future capital funding requirements (equity or debt); the ability of Rubellite to obtain and retain qualified staff and equipment in a timely and cost-efficient manner, as applicable; the retention of key properties; forecast inflation, supply chain access and other assumptions inherent in Rubellite's current guidance and estimates; climate change; severe weather events (including wildfires, floods and drought); the continuance of existing tax, royalty, and regulatory regimes; the accuracy of the estimates of reserves volumes; ability to access and implement technology necessary to efficiently and effectively operate assets; risk of wars or other hostilities or geopolitical events (including the ongoing war in Ukraine and conflicts in the Middle East), civil insurrection and pandemics; risks relating to Indigenous land claims and duty to consult; data breaches and cyber attacks; risks relating to the use of artificial intelligence; changes in laws and regulations, including but not limited to tax laws, royalties and environmental regulations (including greenhouse gas emission reduction requirements and other decarbonization or social policies) and including uncertainty with respect to the interpretation and impact of omnibus Bill C-59 and the related amendments to the Competition Act (Canada), and the interpretation of such changes to the Company's business); political, geopolitical and economic instability; trade policy, barriers, disputes or wars (including new tariffs or changes to existing international trade requirements) and general economic and business conditions and markets, among others.

Undue reliance should not be placed on forward-looking information, which is not a guarantee of performance and is subject to a number of risks or uncertainties, including without limitation those described herein and under "Risk Factors" in the Company's Annual Information Form and MD&A for the year ended December 31, 2024 and in other reports on file with Canadian securities regulatory authorities which may be accessed through the SEDAR+ website www.sedarplus.ca and at Rubellite's website www.rubelliteenergy.com. Readers are cautioned that the foregoing list of risk factors is not exhaustive. Forward-looking information is based on the estimates and opinions of Rubellite’s management at the time the information is released, and Rubellite disclaims any intent or obligation to update publicly any such forward-looking information, whether as a result of new information, future events or otherwise, other than as expressly required by applicable securities law.

ABBREVIATIONS AND CONVENTIONS

The following is a list of abbreviations that may be used in this MD&A:

Measurement:

bbl	barrel
bbl/d	barrels per day
Mbbl	thousand barrels
MMbbl	million barrels
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
GJ	gigajoule

Industry Metrics:

This MD&A contains certain industry metrics which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included in this document to provide readers with additional measures to evaluate Rubellite's performance; however, such measures are not reliable indicators of Rubellite's future performance and future performance may not compare to Rubellite's performance in previous periods and therefore such metrics should not be unduly relied upon.

Volume Conversions:

Barrel of oil equivalent (“boe”) may be misleading, particularly if used in isolation. In accordance with National Instrument 51-101 (“NI 51-101”), a conversion ratio for conventional natural gas of 6 Mcf:1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, utilizing a conversion on a 6 Mcf:1 bbl basis may be misleading as an indicator of value as the value ratio between conventional natural gas and heavy crude oil, based on the current prices of natural gas and crude oil, differ significantly from the energy equivalency of 6 Mcf:1 bbl. A conversion ratio of 1 bbl of heavy crude oil to 1 bbl of NGL has also been used throughout this MD&A.

Initial Production Rates:

Any references in this MD&A to initial production rates are useful in confirming the presence of hydrocarbons; however, such rates are not determinative of the rates at which such wells will continue production and decline thereafter and are not necessarily indicative of long-term performance or ultimate recovery. Readers are cautioned not to place reliance on such rates in calculating the aggregate production for the Company. Such rates are based on field estimates and may be based on limited data available at this time.

Estimated Drilling Locations:

Of the 326.2 net heavy oil drilling development locations disclosed in this MD&A, 93.1 net are proved and 45.6 net are probable undeveloped locations in the McDaniel Reserve Report at year end 2024. Of those heavy oil locations, a total of 8.0 net Figure Lake proved undeveloped, 4.5 net North Waseca proved undeveloped, 4.5 net North Waseca probable undeveloped, and 3.0 South Waseca proved undeveloped have been drilled through 2025. There are 9.5 net proven natural gas locations and 4.4 net probable natural gas locations in the McDaniel Reserve Report at year end 2024. Of those natural gas locations, a total of 1.0 net proven undeveloped gas location has been drilled through 2025. Unbooked drilling locations are the internal estimates of Rubellite based on Rubellite's or the acquired assets prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources (including contingent and prospective). Unbooked locations have been identified by Rubellite's management as an estimation of Rubellite's multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that Rubellite will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and natural gas reserves, resources or production. The drilling locations on which Rubellite will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While a certain number of the unbooked drilling locations have been de-risked by Rubellite drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management of Rubellite has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

Financial and Business Environment:

AECO	Alberta Energy Company
E&E	Exploration and evaluation
ESG	Environmental, social and governance
GAAP	Generally accepted accounting principles
G&A	General and administrative
IAS	International Accounting Standard
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
NGL	Natural gas liquids
PP&E	Property, plant and equipment
WTI	West Texas Intermediate
WCS	Western Canadian Select

SUMMARY OF QUARTERLY RESULTS

($ thousands, except as noted)	Q3 2025	Q2 2025	Q1 2025	Q4 2024
Financial				
Oil and natural gas revenue	**58,290**	60,542	66,607	59,081
Net income (loss) and comprehensive income (loss)	**5,646**	16,051	1,160	26,747
Per share – basic(2)	**0.06**	0.17	0.01	0.31
Per share – diluted(2)	**0.06**	0.17	0.01	0.30
Total assets	**558,709**	561,545	551,889	562,612
Cash flow from operating activities	**34,953**	35,808	27,135	39,402
Adjusted funds flow, after transaction costs(1)(5)	**35,663**	37,311	35,934	31,632
Per share – basic(1)(2)	**0.38**	0.40	0.39	0.36
Per share – diluted(1)(2)	**0.37**	0.39	0.38	0.36
Capital expenditures, including land and other(1)	**35,365**	31,168	24,932	35,537
Acquisitions(3)	**—**	—	—	68,467
Dispositions(3)	**(5,500)**	—	—	—
Common shares (thousands)				
Weighted average – basic	**93,700**	93,279	92,930	87,655
Weighted average – diluted	**96,311**	95,074	95,068	88,546
Operating				
Heavy oil (bbl/d)(4)	**8,338**	8,637	8,339	7,754
Natural gas (Mcf/d)	**20,975**	20,522	22,038	14,140
NGL (bbl/d)(5)	**288**	368	371	275
Daily average sales production (boe/d)	**12,122**	12,425	12,383	10,386
Rubellite average realized oil price(1)				
Oil ($/bbl)	**72.40**	69.98	80.03	76.97
Natural gas ($/Mcf)	**0.66**	1.93	2.16	2.01
NGL ($/bbl)	**56.12**	57.92	67.54	61.32
Total average realized price ($/boe)	**52.27**	53.54	59.77	61.83

($ thousands, except as noted)	Q3 2024	Q2 2024	Q1 2024	Q4 2023
Financial				
Oil revenue	43,682	35,798	29,823	27,224
Net income (loss) and comprehensive income (loss)	15,010	12,368	(4,153)	9,523
Per share – basic(2)	0.23	0.20	(0.07)	0.15
Per share – diluted(2)	0.23	0.19	(0.07)	0.15
Total assets	432,836	281,549	267,298	271,153
Cash flow from operating activities	19,973	19,916	16,497	18,963
Adjusted funds flow, after transaction costs(1)(5)	23,029	20,664	18,452	16,923
Per share – basic(1)(2)	0.35	0.33	0.30	0.27
Per share – diluted(1)(2)	0.35	0.33	0.30	0.27
Capital expenditures, including land and other(1)	36,650	23,927	12,792	26,320
Acquisitions(3)	62,732	—	—	33,173
Dispositions(3)	—	—	—	(7,900)
Common shares (thousands)				
Weighted average – basic	65,834	62,494	62,457	62,440
Weighted average – diluted	66,571	63,446	62,457	62,958
Operating				
Daily average oil sales production (boe/d)	5,954	4,503	4,514	4,209
Rubellite average realized oil price(1)				
Average realized oil price ($/bbl)	79.75	87.35	72.60	70.31

(1) Non-GAAP measure, ratio or supplementary measure. See "Non-GAAP and Other Financial Measures".
(2) Per share amounts are calculated using the weighted average number of basic or diluted common shares.
(3) Includes cash and non-cash consideration.
(4) Conventional heavy oil sales production excludes tank inventory volumes.
(5) Q4 2024 includes $4.2 million in transaction costs related to the Recombination Transaction with Perpetual, Q3 2024 includes $2.0 million in transaction costs related to the BMEC Acquisition and Q4 2023 includes $0.1 million in transaction costs related to a Clearwater asset acquisition.

Oil and natural gas revenue has ranged between $27.2 million and $66.6 million over the prior eight quarters largely due to increasing sales volumes from 4,209 boe/d to 12,425 boe/d, partially offset by volatility in commodity pricing. Net income (loss) has ranged between a loss of $4.2 million and income of $26.7 million primarily due to increased production, corporate acquisitions and dispositions, volatility of commodity prices and its impact on revenue, royalties and realized and unrealized risk management contract gains and losses and deferred income taxes.

RUBELLITE ENERGY CORP.
Condensed Interim Consolidated Statements of Financial Position

As at	September 30, 2025	December 31, 2024
(*Cdn$ thousands, unaudited*)		
Assets		
Current assets		
Cash	**$ —**	$ 2,555
Accounts receivable	**20,407**	26,349
Prepaid expenses, deposits and other	**2,729**	2,752
Product inventory	**3,805**	3,275
Risk management contracts (note 15)	**4,690**	9,783
	31,631	44,714
Property, plant and equipment (note 3)	**477,747**	461,996
Exploration and evaluation (note 4)	**32,570**	29,106
Right-of-use asset (note 5)	**4,602**	4,930
Deferred tax asset (note 13)	**11,847**	21,437
Risk management contracts (note 15)	**312**	429
Total assets	**$ 558,709**	$ 562,612
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 54,656**	$ 60,451
Risk management contracts (note 15)	**812**	2,765
Lease liabilities (note 6)	**387**	357
Share-based compensation liability (note 9)	**5,346**	5,357
Decommissioning obligations (note 7a)	**1,415**	2,000
Other provision (note 7b)	**3,750**	3,750
	66,366	74,680
Bank debt (note 11)	**90,639**	108,500
Term loan (note 12)	**19,128**	19,027
Lease liabilities (note 6)	**4,432**	4,608
Risk management contracts (note 15)	**—**	225
Share-based compensation liability (note 9)	**1,626**	914
Decommissioning obligations (note 7a)	**31,051**	29,817
Other provision (note 7b)	**11,440**	14,824
Total liabilities	**224,682**	252,595
Equity		
Share capital (note 8)	**207,466**	206,313
Contributed surplus	**2,863**	2,863
Retained earnings	**123,698**	100,841
Total equity	**334,027**	310,017
Total liabilities and equity	**$ 558,709**	$ 562,612

Commitments (note 3)

See accompanying notes to the condensed interim consolidated financial statements.

RUBELLITE ENERGY CORP.
Condensed Interim Consolidated Statements of Income and Comprehensive Income

	Three months ended September 30,		Nine months ended September 30,	
	2025	2024	**2025**	2024
(Cdn$ thousands, except per share amounts, unaudited)				
Revenue				
Oil and natural gas (note 10)	**$ 58,290**	$ 43,682	**$ 185,439**	$ 109,303
Royalties	**(8,003)**	(5,259)	**(25,083)**	(12,529)
	50,287	38,423	**160,356**	96,774
Realized gain (loss) on risk management contracts (note 15)	**3,966**	168	**8,601**	(578)
Unrealized gain (loss) on risk management contracts (note 15)	**(7,444)**	11,418	**(3,032)**	1,096
Other income	**75**	—	**580**	—
	46,884	50,009	**166,505**	97,292
Expenses				
Production and operating	**7,281**	4,634	**22,830**	9,978
Transportation	**5,201**	4,202	**18,139**	10,581
General and administrative	**3,615**	2,668	**12,044**	7,094
Share based payments (note 9)	**2,257**	824	**4,607**	2,203
Exploration and evaluation (note 4)	**—**	13	**3,316**	288
Gain on disposition (note 3c)	**(5,500)**	—	**(5,500)**	—
Depletion and depreciation (note 3, 5)	**23,614**	13,118	**69,950**	30,759
Transaction costs	**—**	2,010	**132**	2,010
	10,416	22,540	**40,987**	34,379
Finance expense (note 14)	**(3,008)**	(2,134)	**(8,669)**	(4,354)
Income before income tax	**7,408**	20,406	**32,318**	30,025
Taxes				
Deferred expense (note 13)	**(1,762)**	(5,396)	**(9,461)**	(6,800)
Net income and comprehensive income	**$ 5,646**	$ 15,010	**$ 22,857**	$ 23,225
Net income per share (note 8c)				
Basic	**$ 0.06**	$ 0.23	**$ 0.25**	$ 0.37
Diluted	**$ 0.06**	$ 0.23	**$ 0.24**	$ 0.36

See accompanying notes to the condensed interim consolidated financial statements.

RUBELLITE ENERGY CORP.
Condensed Interim Consolidated Statements of Changes in Equity

(Cdn$ thousands, except share amounts, unaudited)	*Share Capital (thousands)*	*Share Capital ($thousands)*	Contributed surplus	Retained earnings	Total Equity
Balance at December 31, 2024	93,044	$ 206,313	$ 2,863	$ 100,841	$ 310,017
Net income	—	—	—	22,857	22,857
Common shares issued, net of issue costs (note 8)	—	(129)	—	—	(129)
Common shares issued, share-based payment plan (note 9)	626	1,282	—	—	1,282
Balance at September 30, 2025	**93,670**	**$ 207,466**	**$ 2,863**	**$ 123,698**	**$ 334,027**

(Cdn$ thousands, except share amounts, unaudited)	*Share Capital (thousands)*	*Share Capital ($thousands)*	Share purchase warrants	Contributed surplus	Retained earnings	Total Equity
Balance at December 31, 2023	62,456	$ 143,033	$ 2,000	$ 3,410	$ 50,868	$ 199,311
Net income	—	—	—	—	23,225	23,225
Common shares issued, net of issue costs (note 8)	5,000	10,350	—	—	—	10,350
Common shares issued, share-based payment plan (note 9)	137	472	—	(1,379)	—	(907)
Share-based payments (note 9)	—	—	—	2,203	—	2,203
Balance at September 30, 2024	67,593	$ 153,855	$ 2,000	$ 4,234	$ 74,093	$ 234,182

See accompanying notes to the condensed interim consolidated financial statements.

RUBELLITE ENERGY CORP.
Condensed Interim Consolidated Statements of Cash Flows

	Three months ended September 30, 2025	Three months ended September 30, 2024	Nine months ended September 30, 2025	Nine months ended September 30, 2024
(*Cdn$ thousands, unaudited*)				
Cash flows from operating activities				
Net income	**$ 5,646**	$ 15,010	**$ 22,857**	$ 23,225
Adjustments to add (deduct):				
Depletion and depreciation (note 3, 5)	**23,614**	13,118	**69,950**	30,759
Share-based payments (note 9)	**2,257**	824	**4,607**	2,203
Deferred tax expense (note 13)	**1,762**	5,396	**9,461**	6,800
Unrealized loss (gain) on risk management contracts (note 15)	**7,444**	(11,418)	**3,032**	(1,096)
Non-cash finance expense (note 14)	**440**	99	**1,303**	232
Gain on dispositions (note 3c)	**(5,500)**	—	**(5,500)**	—
Non-cash exploration and evaluation expense (note 4)	**—**	—	**3,198**	22
Payment for share-based compensation (note 9)	**(1,539)**	—	**(2,624)**	—
Payment for other provision (note 7b)	**—**	—	**(3,750)**	—
Decommissioning obligations settled (note 7a)	**(394)**	(122)	**(1,286)**	(270)
Change in non-cash working capital	**1,223**	(2,934)	**(3,352)**	(5,489)
Net cash flows from operating activities	**34,953**	19,973	**97,896**	56,386
Cash flows from (used in) financing activities				
Payment for share-based compensation (note 9)	**—**	—	**—**	(574)
Term loan, net of issue costs (note 12)	**—**	18,964	**—**	18,964
Payment lease liabilities (note 6)	**(89)**	—	**(286)**	—
Repayment of acquired bank debt (note 3c)	**—**	(14,215)	**—**	(14,215)
Change in bank debt (note 11)	**(15,573)**	61,322	**(17,861)**	62,836
Net cash flows from (used in) financing activities	**(15,662)**	66,071	**(18,147)**	67,011
Cash flows used in investing activities				
Development and production expenditures (note 3)	**(34,854)**	(28,348)	**(84,407)**	(58,115)
Corporate expenditures (note 3)	**(199)**	(52)	**(396)**	(2,969)
Exploration and evaluation expenditures (note 4)	**(312)**	(8,250)	**(6,662)**	(12,285)
Acquisitions (note 3c)	**—**	(62,732)	**—**	(62,732)
Proceeds from dispositions (note 3c)	**5,500**	—	**5,500**	—
Change in non-cash working capital	**10,574**	13,338	**3,661**	12,704
Net cash flows used in investing activities	**(19,291)**	(86,044)	**(82,304)**	(123,397)
Change in cash	**—**	—	**(2,555)**	—
Cash, beginning of period	**—**	—	**2,555**	—
Cash, end of period	**$ —**	$ —	**$ —**	$ —

See accompanying notes to the condensed interim consolidated financial statements.

1. REPORTING ENTITY

Rubellite Energy Corp. ("Rubellite" or the "Company") is an oil and natural gas exploration and production company headquartered in Calgary, Alberta.

The address of the Company's registered office is 3200, 605 – 5 Avenue S.W., Calgary, Alberta, T2P 3H5.

The condensed interim consolidated financial statements of the Company are comprised of the accounts of Rubellite Energy Corp. and its wholly owned subsidiaries: Rubellite Energy Inc., Ukalta GP Inc., Ukalta Limited Partnership, Perpetual Operating Corp. and Perpetual Energy Partnership.

2. BASIS OF PREPARATION

These condensed interim consolidated financial statements have been prepared in accordance with IAS 34 Interim Financial Reporting and do not include all of the information required for full annual financial statements. These condensed interim consolidated financial statements should be read in conjunction with the Company's consolidated financial statements as at and for the year ended December 31, 2024 which were prepared in conformity with IFRS Accounting Standards as issued by the International Accounting Standards Board.

The accounting policies, basis of measurement, critical accounting judgments and significant estimates used to prepare the annual consolidated financial statements as at and for the year ended December 31, 2024 have been applied in the preparation of these condensed interim consolidated financial statements.

These financial statements were approved and authorized for issue by the Board of Directors on November 5, 2025.

3. PROPERTY, PLANT AND EQUIPMENT

a) Property, Plant And Equipment

	Development and Production Assets	Corporate Assets	Total
Cost			
December 31, 2023	$ 245,156	$ —	$ 245,156
Additions	90,680	3,097	93,777
Transfer from exploration and evaluation (note 4)	20,796	—	20,796
Acquisitions (note 3c)	173,818	2,737	176,555
Change in decommissioning obligations related to PP&E (note 7a)	19,532	—	19,532
December 31, 2024	$ 549,982	$ 5,834	$ 555,816
Additions	**84,407**	**396**	**84,803**
Change in decommissioning obligations related to PP&E (note 7a)	**1,124**	**—**	**1,124**
September 30, 2025	**$ 635,513**	**$ 6,230**	**$ 641,743**
Accumulated depletion and depreciation			
December 31, 2023	$ (42,953)	$ —	$ (42,953)
Depletion and depreciation	(50,317)	(550)	(50,867)
December 31, 2024	$ (93,270)	$ (550)	$ (93,820)
Depletion and depreciation(1)	**(69,115)**	**(1,061)**	**(70,176)**
September 30, 2025	**$ (162,385)**	**$ (1,611)**	**$ (163,996)**
Carrying amount			
December 31, 2024	$ 456,712	$ 5,284	$ 461,996
September 30, 2025	**$ 473,128**	**$ 4,619**	**$ 477,747**

(1) During the period ended September 30, 2025, depletion, as presented in the table, excludes $0.7 million which has been capitalized to inventory (September 30, 2024 - $0.1 million).

As at September 30, 2025, future development costs of $387.5 million (December 31, 2024 – $436.3 million) associated with proved and probable oil and gas reserves were included in the depletion calculation and an estimated $9.2 million (December 31, 2024 – $8.7 million) of salvage value for production equipment. Depletion expense was $69.1 million (December 31, 2024 - $50.3 million) on development and production assets for the nine months ended September 30, 2025.

During the nine months ended September 30, 2025, the Company added $0.4 million of corporate assets (December 31, 2024 - $5.8 million) and recorded depreciation expense of $1.1 million (December 31, 2024 - $0.6 million).

The Company has a drilling commitment on certain gross overriding royalty ("GORR") lands that must be fulfilled by June 30, 2026 (the "Commitment Date"). In the event the Company fails to fulfill the drilling commitment, the Company is required to pay $0.1 million per well not spud by the Commitment Date. As at September 30, 2025, the Company has drilled twenty four (24.0 net) of the fifty nine (59.0 net) wells that are required to meet the drilling commitment. Subsequent to September 30, 2025, the Company has drilled an additional three (3.0 net) for a total of twenty seven (27.0 net) wells required to meet the drilling commitment.

b) Impairment

There were no indicators of impairment related to the Company's cash generating units ("CGU"s) as at September 30, 2025 and December 31, 2024, and the Company did not transfer E&E to PP&E during the first nine months of 2025; therefore, no impairment test was required.

The Company transferred $20.8 million of E&E to PP&E during 2024 and performed the required impairment test to estimate the recoverable amount of the CGU. It was determined that the recoverable amount of the CGU exceeded its carrying value, resulting in no impairment.

c) Acquisitions and Dispositions

During the third quarter of 2025, the Company disposed of undeveloped land for proceeds of $5.5 million and recorded a corresponding gain on disposition.

Perpetual Energy Inc. ("Perpetual")

Effective October 31, 2024, Rubellite Energy Inc. and Perpetual effected a Recombination Transaction by way of an arrangement resulting in the recombination of the two entities into a new entity being Rubellite Energy Corp. In accordance with the Recombination Transaction, (i) holders of common shares of Rubellite Energy Inc. received (1) common share of the Company for every (1) common share of Rubellite Energy Inc. held, (ii) holders of common shares of Perpetual received (1) common share of the Company for every (5) Perpetual shares held, and (iii) Perpetual's outstanding senior notes ($26.2 million in face value) were converted into 11.6 million common shares of the Company at a conversion price of $2.25 per common share (note 8b). The Recombination Transaction resulted in the issuance of 25.4 million common shares issued at Rubellite's closing share price on October 31, 2024, of $2.04 per share and the settlement of a pre-existing relationship for a total purchase price of $47.7 million.

The conventional natural gas assets acquired in this transaction are included in the West Central CGU.

Buffalo Mission Energy Corp. ("Buffalo Mission")

Effective August 2, 2024, Rubellite Energy Inc. acquired all of the issued and outstanding common shares of Buffalo Mission for a total purchase price of $96.6 million, inclusive of $23.5 million of Buffalo Mission's assumed net debt, which consisted of $62.7 million in cash and the issuance of 5.0 million of common shares (note 8b) of Rubellite to certain shareholders of Buffalo Mission valued at $10.4 million using Rubellite Energy Inc.'s closing share price on August 2, 2024 of $2.07 per share (the "BMEC Acquisition"). As part of the transaction, Rubellite repaid $14.2 million of acquired debt in the third quarter of 2024. All assets acquired are included in the Company's Eastern Heavy Oil CGU.

4. EXPLORATION AND EVALUATION

	September 30, 2025	December 31, 2024
Balance, beginning of period	**$ 29,106**	$ 32,301
Acquisitions (note 3c)	**—**	2,692
Additions	**6,662**	15,129
Transfer to property, plant, and equipment (note 3a)	**—**	(20,796)
Exploration and evaluation expense	**(3,198)**	(220)
Balance, end of period	**$ 32,570**	$ 29,106

Exploration and evaluation ("E&E") expense was $3.3 million (December 31, 2024 - $0.5 million) for the nine months ended September 30, 2025, which included $3.2 million related to two (2.0 net) exploration wells and associated lands that were previously recorded as E&E and $0.1 million of costs directly charged to E&E expense.

Impairment of E&E assets

E&E assets are tested for impairment when internal or external indicators of impairment exist as well as upon reclassification to oil and gas interests in PP&E. At September 30, 2025, the Company conducted an assessment of the indicators of impairment for the Company's E&E assets. In performing the assessment, management has determined that there were no indicators of impairment.

5. RIGHT-OF-USE ASSETS

The Company leases several assets including office space, vehicles, and other leases. Information about lease obligations for which the Company is a lessee is presented below:

	Head office	Vehicles	Other leases	Total
Cost				
December 31, 2024	$ 4,782	$ 190	$ 64	$ 5,036
Additions	—	140	—	140
September 30, 2025	**$ 4,782**	**$ 330**	**$ 64**	**$ 5,176**
Accumulated depreciation				
December 31, 2024	$ (77)	$ (23)	$ (6)	$ (106)
Depreciation	(344)	(95)	(29)	(468)
September 30, 2025	**$ (421)**	**$ (118)**	**$ (35)**	**$ (574)**
Carrying amount				
December 31, 2024	$ 4,705	$ 167	$ 58	$ 4,930
September 30, 2025	**$ 4,361**	**$ 212**	**$ 29**	**$ 4,602**

6. LEASE LIABILITIES

	September 30, 2025	December 31, 2024
Balance, beginning of year	**$ 4,965**	$ —
Additions (note 5)	**140**	—
Acquisition (note 3c)	**—**	5,036
Interest on lease liabilities (note 14)	**239**	55
Payments	**(525)**	(126)
Total lease liabilities	**$ 4,819**	$ 4,965
Current	**$ 387**	$ 357
Non-current	**4,432**	4,608
Total lease liabilities	**$ 4,819**	$ 4,965

Lease terms are negotiated on an individual basis and contain a wide range of terms and conditions. Incremental borrowing rates used to measure the present value of the future lease payments at September 30, 2025 were between 4.3% and 6.6% (December 31, 2024 - 4.3% and 6.6%).

7. PROVISIONS

a) Decommissioning obligations

	September 30, 2025	December 31, 2024
Balance, beginning of period	**$ 31,817**	$ 8,593
Liabilities settled	**(1,286)**	(451)
Obligations incurred	**2,104**	3,535
Obligations acquired (note 3c)	**—**	3,827
Change in rate on acquisition (note 3c)	**—**	13,586
Revisions to estimates	**(980)**	2,411
Accretion (note 14)	**811**	316
Total decommissioning obligations, end of period	**$ 32,466**	$ 31,817
Decommissioning obligations - current	**$ 1,415**	$ 2,000
Decommissioning obligations - non-current	**31,051**	29,817
Total decommissioning obligations	**$ 32,466**	$ 31,817

Decommissioning obligations are estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities, and the estimated timing of the costs to be incurred in future periods.

The increase in the provision due to the passage of time, which is referred to as accretion, is recognized as non-cash finance expense in the consolidated statements of income and comprehensive income. Decommissioning obligations are further adjusted at each period end date for changes in the risk-free interest rate, after considering additions and dispositions of PP&E. Decommissioning obligations are also adjusted for revisions to future cost estimates and the estimated timing of costs to be incurred in future periods.

The following significant assumptions were used to estimate the Company's decommissioning obligations:

	September 30, 2025	December 31, 2024
Undiscounted obligations	**$ 43,596**	$ 42,085
Average risk-free rate	**3.6%**	3.3%
Inflation rate	**2.0%**	1.8%
Expected timing of settling obligations	**1 to 25 years**	1 to 25 years

b) Other provision

	September 30, 2025	December 31, 2024
Balance, beginning of period	**$ 18,574**	$ —
Provision acquired (note 3c)	**—**	18,481
Payments	**(3,750)**	—
Accretion (note 14)	**366**	93
Total Other provision, end of period	**$ 15,190**	$ 18,574
Other provision - current	**$ 3,750**	$ 3,750
Other provision - non-current	**11,440**	14,824
Total other provision	**$ 15,190**	$ 18,574

The Other provision was assumed as part of the Recombination Transaction and relates to a "Settlement Agreement" Perpetual entered into to resolve litigation by providing amounts to settle asset retirement obligations without any party admitting liability, wrongdoing or violation of laws, regulations, public policy or fiduciary duties. The Company will make annual installment payments of $3.75 million until the total amount of the Settlement Principal is paid. The annual scheduled payment was made on March 28, 2025 and all scheduled payments made prior to March 28, 2026 will have the interest forgiven. As of March 28, 2026, interest will accrue and be payable on the outstanding Settlement Principal annually at an interest rate equal to the applicable Bank of Canada prime rate on the date of payment. The Company is able to pre-pay all, or any portion, of the outstanding balance of the Settlement Principal at any time without bonus or penalty. The Other provision is a second-lien obligation of the Company.

The following assumptions were used to estimate the Company's Other provision:

	September 30, 2025	December 31, 2024
Undiscounted obligation	**$ 16,191**	$ 19,941
Average risk-free rate	**3.0%**	3.0%
Expected timing of settling obligation	**4.5 years**	5.3 years

8. SHARE CAPITAL

a) Authorized

Authorized capital consists of an unlimited number of common shares.

b) Issued and outstanding

	September 30, 2025		December 31, 2024	
	Shares *(thousands)*	**Amount *($thousands)***	Shares *(thousands)*	Amount *($thousands)*
Balance, beginning of period	**93,044**	**$ 206,313**	62,456	$ 143,033
Common shares issued, net of issue costs (note 3c)	**—**	**(129)**	30,359	62,082
Issued pursuant to share-based plans	**626**	**1,282**	229	1,567
Share issue costs	**—**	**—**	—	(369)
Balance, end of period	**93,670**	**$ 207,466**	93,044	$ 206,313

During the period ended September 30, 2025, the Company issued 0.6 million common shares (December 31, 2024 - 0.2 million common shares) pursuant to share-based compensation plans.

On October 31, 2024, in conjunction with the closing of the Recombination Transaction, Rubellite issued 25.4 million common shares which were valued at $51.7 million using the Company's share price on the closing date of the transaction of $2.04 per share.

On August 2, 2024, in conjunction with the closing of the acquisition of Buffalo Mission, Rubellite issued 5.0 million common shares to certain shareholders of Buffalo Mission, which were valued at $10.4 million using the Company's share price on the closing date of the transaction of $2.07 per share.

c) Per share information

(*thousands, except per share amounts*)	Three months ended September 30, **2025**	2024	Nine months ended September 30, **2025**	2024
Net income	**$ 5,646**	15,010	**$ 22,857**	$ 23,225
Weighted average shares				
Issued common shares	**93,670**	67,593	**93,670**	67,593
Effect of shares held in trust(1)	**(82)**	—	**(82)**	—
Issued common shares, net of shares held in trust(2)	**93,588**	67,593	**93,588**	67,593
Weighted average common shares outstanding – basic	**93,700**	65,834	**93,211**	63,592
Weighted average common shares outstanding – diluted	**96,311**	66,571	**95,838**	64,599
Net income per share – basic	**$ 0.06**	$ 0.23	**$ 0.25**	$ 0.37
Net income per share – diluted	**$ 0.06**	$ 0.23	**$ 0.24**	$ 0.36

(1) As result of the Recombination Transaction, the Company has compensation agreements in place with employees whereby they may be entitled to receive shares of the Company purchased on the open market by a trustee (note 9).
(2) Share capital is presented net of the shares held by the Trustee that have not been issued to employees. As at September 30, 2025 there were 0.1 million shares held in trust (December 31, 2024 - 0.2 million).

Per share amounts have been calculated using the weighted average number of common shares outstanding. For the three and nine months ended September 30, 2025, 8.2 million common shares and 8.2 million common shares, respectively (three and nine months ended September 30, 2024 - 7.1 million common shares and 6.8 million common shares, respectively) issuable upon the exercise and/or settlement of share options, restricted share units and performance share units were excluded from the diluted weighted average number of common shares outstanding as they were anti-dilutive.

9. SHARE-BASED PAYMENTS

The following table summarizes the changes in the share-based compensation liability:

	September 30, 2025	December 31, 2024
Balance, beginning of period	**$ 6,271**	$ —
Reclassified from contributed surplus(1)	**—**	3,696
Share-based compensation liability acquired	**—**	2,925
Share-based payment expense	**4,852**	—
Fair value adjustment	**(245)**	282
Cash settlement	**(2,624)**	(632)
Equity settlement	**(1,282)**	—
Balance, end of period(2)	**$ 6,972**	$ 6,271
Share-based compensation liability - current	**$ 5,346**	$ 5,357
Share-based compensation liability - non-current	**1,626**	914
Total share-based compensation liabilities	**$ 6,972**	$ 6,271

(1) During 2024, the Company modified its share options, performance share units and restricted share units from equity-settled to cash-settled share-based compensation awards. The fair values of the awards previously expensed have been reclassified from contributed surplus to a share-based compensation liability.
(2) The Company's share-based payment liability can be settled through the issuance of cash or shares.

The components of share-based compensation expense are as follows:

	Three months ended September 30, **2025**	2024	Nine months ended September 30, **2025**	2024
Share-based payment expense	**$ 1,764**	$ 824	**$ 4,852**	$ 2,203
Fair value adjustment	**493**	—	**(245)**	—
Share-based payment expense	**$ 2,257**	$ 824	**$ 4,607**	$ 2,203

The following tables summarize information about options, rights and awards outstanding:

Compensation awards

(number of awards, thousands)	Share options	Performance share units	Restricted share units	Total
December 31, 2024	3,052	605	2,526	6,183
Granted	—	1,620	1,892	3,512
Exercised for common shares	(41)	(562)	(390)	(993)
Exercised for cash	—	—	(525)	(525)
Performance adjustment	—	281	—	281
Forfeited	(34)	—	(124)	(158)
September 30, 2025	**2,977**	**1,944**	**3,379**	**8,300**

Compensation awards - Recombination Transaction(1)(2)

(number of awards, thousands)	Deferred Options	Deferred Shares	Share options	Performance share rights	Total
December 31, 2024(3)	1,189	568	902	532	3,191
Exercised for common shares	—	—	(53)	—	(53)
Exercised for shares held in trust	(90)	(39)	—	—	(129)
Exercised for cash	(163)	(7)	(60)	(111)	(341)
Performance adjustment	—	—	—	(111)	(111)
Forfeited	—	(15)	—	—	(15)
September 30, 2025(3)	**936**	**507**	**789**	**310**	**2,542**

(1) Recognized as part of the Recombination Transaction.
(2) Awards previously issued by Perpetual, which were acquired through the Recombination Transaction, were adjusted at the equity conversion ratio of 5:1.
(3) Total awards outstanding include 1.4 million legacy awards that can be settled for cash or from shares in the trust as opposed to treasury. Shares in the trust as at September 30, 2025 were 0.1 million (December 31, 2024 - 0.2 million) (note 10c).

During the nine months ended September 30, 2025, the Company granted 3.5 million share-based compensation awards, comprised of performance share units and restricted share units under the Company's share-based compensation plans.

a) Deferred options

As a result of the Recombination Transaction, the Company has a deferred option plan which includes agreements with certain employees whereby they may be entitled to receive cash or shares of the Company purchased on the open market by an independent trustee if they remain employees of the Company and exercise their deferred options. Deferred options generally vest over four years, one quarter on each year of the term, with expiry occurring five years after issuance. The shares purchased by the independent trustee are reported as shares held in trust (note 8c).

The Company uses the Black-Scholes pricing model to calculate the estimated fair value of the deferred options and performance based long-term incentive awards. The following assumptions were used to arrive at the estimate of fair value as at September 30, 2025:

	September 30, 2025	December 31, 2024
Dividend yield (%)	—	—
Forfeiture rate (%)	**5.00**	5.00
Expected volatility (%)	**44.70**	48.61
Risk-free interest rate (%)	**2.46**	2.89
Contractual life (years)	**5.0**	5.0
Weighted average share price at grant date	**$ 0.98**	$ 0.81
Closing share price	**$ 2.26**	$ 2.12

b) Share options

Rubellite’s share option plan provides a long-term incentive to directors, executive officers, employees or consultants associated with the Company’s long-term performance. The Board of Directors administers the share option plan and determines participants, number of share options and terms of vesting. The exercise price of the share options granted shall not be less than the value of the weighted average trading price for the Company’s common shares for the five trading days immediately preceding the date of grant. Share options granted vest evenly over four years, commencing on the first anniversary, with expiry occurring five years after issuance. Share options include legacy Perpetual share options from the Recombination Transaction, adjusted for the share exchange ratio of 5:1 and were awarded under the same terms.

The Company uses the Black-Scholes pricing model to calculate the estimated fair value of the share option awards. The following assumptions were used to arrive at the estimate of fair value as at September 30, 2025:

	September 30, 2025	December 31, 2024
Dividend yield (%)	**—**	—
Forfeiture rate (%)	**5.00**	5.00
Expected volatility (%)	**45.00**	48.61
Risk-free interest rate (%)	**2.47**	2.89
Contractual life (years)	**5.0**	5.0
Weighted average share price at grant date	**$ 2.50**	$ 0.81
Closing share price	**$ 2.26**	$ 2.12

c) Deferred shares

As a result of the Recombination Transaction, the Company has a deferred share plan which includes agreements in place with directors and certain employees. In the case of directors, the deferred shares granted vest upon retirement from the Board of Directors and for employees, the deferred shares vest over a two year period if they remain employees of the Company during such time. Upon vesting, directors and employees may be entitled to receive, at the discretion of the Board of Directors, cash, a grant of restricted rights (note 9e), or shares of the Company purchased on the open market by an independent trustee. The shares purchased by the independent trustee are reported as shares held in trust (note 8c).

The Company accounts for the deferred shares using the cash-settled method under IFRS 2 and uses an intrinsic pricing model to calculate the estimated fair value of the deferred shares at the end of each reporting period. The share-based compensation liability is reduced by an estimated forfeiture rate of 5% for outstanding awards and the Company's closing share price. The deferred shares were revalued at September 30, 2025 using Rubellite's closing share price of $2.26 per share.

d) Performance share units and performance share rights

The Company has a performance share unit plan for the Company's executive officers. Performance share units granted under the performance share unit plan vest two years after the date upon which the performance units were granted for awards issued in 2023 and 2024 and over three years for awards granted in 2025. The performance share units that vest and become redeemable for equivalent common shares are a multiple of the performance share units granted, dependent upon the achievement of certain performance metrics over the vesting period. Vested performance share units can be settled in cash or in common shares of the Company at the discretion of the Board of Directors. Performance share units are forfeited if participants of the performance share unit plan leave the organization other than through retirement or termination without cause prior to the vesting date. Performance share rights, which were acquired from Perpetual in the Recombination Transaction, were awarded under the same terms and were adjusted for the exchange ratio of 5:1 through the Recombination Transaction.

The fair value of a performance share unit award is determined at the date of grant by using the closing price of common shares multiplied by the estimated performance multiplier. A performance factor of 2.0 was applied to performance share units which vested in the first quarter of 2025. As at September 30, 2025, performance factors of 1.3 and 0.9 has been assumed for unvested performance share units granted in 2024 and 2025, respectively. Fluctuations in share-based payments may occur due to changes in estimates of performance outcomes.

The fair value of the legacy Perpetual performance share right awards is determined at the date of grant by using the closing price of common shares multiplied by the estimated performance multiplier. A performance factor of 0.5 was applied to performance share rights which vested in the first quarter of 2025 for awards granted by Perpetual in 2023. As at September 30, 2025, a performance factor of 0.6 has been assumed for unvested performance share rights granted in 2024 which were acquired through the Recombination Transaction. Fluctuations in share-based payments may occur due to changes in estimates of performance outcomes.

The Company accounts for the performance share units and performance share rights using the cash-settled method under IFRS 2 and uses an intrinsic pricing model to calculate the estimated fair value at the end of each reporting period. The share-based compensation liability is reduced by an estimated forfeiture rate of 5% for outstanding awards and the Company's closing share price. The performance share units were revalued at September 30, 2025 using Rubellite's closing share price of $2.26 per share.

e) Restricted share units

The Company has a restricted share unit plan for directors, officers, employees or consultants. The restricted share units ("RSUs") vest proportionately annually over a two year period for units granted prior to November 1, 2024 and vest proportionately annually over a three year period for units granted after November 1, 2024. The restricted share units that vest can be settled in cash or in common shares, at the discretion of the Company.

The Company accounts for the restricted share units using the cash-settled method under IFRS 2 and uses an intrinsic pricing model to calculate the estimated fair value at the end of each reporting period. The share-based compensation liability is reduced by an estimated forfeiture rate of 5% for outstanding awards and the Company's closing share price on September 30, 2025 of $2.26 per share.

10. OIL AND GAS REVENUE

The Company sells its production pursuant to fixed or variable price contracts. The transaction price for variable priced contracts is based on the commodity price, adjusted for quality, location or other factors, whereby each component of the pricing formula can be either fixed or variable, depending on the contract terms. Under the contracts, the Company is required to deliver fixed or variable volumes of heavy crude oil, natural gas or NGL as may be applicable to the contract counterparty. Revenue is recognized when a unit of production is delivered to the contract counterparty. The amount of revenue recognized is based on the agreed transaction price, whereby any variability in revenue relates specifically to the Company's efforts to transfer production, therefore the resulting revenue is allocated to the sales production delivered in the period during which the variability occurs. As a result, none of the variable revenue is considered constrained.

The Company's properties currently produce heavy crude oil, natural gas and NGL volumes which are mostly sold under floating contracts of varying price and volume terms of up to one year with established creditworthy counterparties. Revenues are typically collected on the 25th day of the month following production and delivery to sales points. Included in accounts receivable at September 30, 2025 is $16.9 million of revenue related to September 2025 sales production (December 31, 2024 - $22.0 million of revenue related to December 2024 sales production).

	Three months ended September 30,		Nine months ended September 30,	
	2025	2024	**2025**	2024
Oil	**$ 55,536**	$ 43,682	**$ 170,599**	$ 109,303
Natural gas	**1,268**	—	**9,156**	—
NGL	**1,486**	—	**5,684**	—
Total oil and natural gas revenue	**$ 58,290**	$ 43,682	**$ 185,439**	$ 109,303

11. BANK DEBT

As at September 30, 2025, the Company's first lien credit facility had a borrowing limit of $140.0 million (December 31, 2024 - $140.0 million). The initial term is to May 31, 2026 and may be extended for a further twelve months to May 31, 2027 subject to lender approval. If not extended by May 31, 2026, all outstanding advances would be repayable on May 31, 2027. The next semi-annual borrowing base redetermination is scheduled on or before November 30, 2025.

As at September 30, 2025, $90.6 million was drawn against the credit facility (December 31, 2024 - $108.5 million) and $1.4 million (December 31, 2024 - $3.6 million) of letters of credit have been issued. Borrowings under the credit facility bear interest at the lenders' prime rate or CORRA rates, plus applicable margins and standby fees. The applicable CORRA margins range between 2.8% and 6.3%. The effective aggregate interest rate on the credit facility at September 30, 2025 was 6.2% per annum. For the period ended September 30, 2025, if interest rates changed by 1% with all other variables held constant, the impact on cash finance expense and net income and comprehensive income would be $0.7 million.

The credit facility is secured by general first lien security agreements covering all present and future property of the Company.

At September 30, 2025, the credit facility was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

12. TERM LOAN

			September 30, 2025		December 31, 2024	
	Maturity date	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
Term loan	August 2, 2029	11.5%	**$ 20,000**	**$ 19,128**	$ 20,000	$ 19,027

On August 2, 2024, Rubellite entered into a senior secured second-lien term loan which was placed, directly or indirectly, with certain directors and officers, and their affiliates, of Rubellite and the Company's significant shareholder for $20.0 million. The term loan bears interest at 11.5% annually with interest payments to be paid quarterly, matures in five years from the date of issue, and can be repaid by the Company without penalty at any time. In conjunction with the closing of the Recombination Transaction, the term loan was converted to a third-lien obligation of the Company without any other modifications.

During the period ended September 30, 2025, Rubellite paid $1.7 million in cash interest payments to the holders of the term loan (September 30, 2024 - $0.3 million).

At September 30, 2025, the term loan has been recorded at the present value of future cash flows, net of $0.9 million (December 31, 2024 - $1.0 million) in issue and discount costs which are amortized over the remaining term using a weighted average effective interest rate of 13.0%.

The term loan is not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

At September 30, 2025 and December 31, 2024, entities controlled or directed by the Company's Chief Executive Officer ("CEO") hold $18.4 million of the outstanding term loan.

13. DEFERRED TAXES

The following table summarizes the continuity of the net deferred tax asset of the Company:

	December 31, 2024	Recognized in earnings	Recognized in equity	**September 30, 2025**
Assets (liabilities):				
Property, plant and equipment	$ (30,903)	$ (4,627)	$ —	**$ (35,530)**
Decommissioning obligations	7,318	149	—	**7,467**
Fair value of derivatives	(1,661)	697	—	**(964)**
Other liabilities	4,049	(1,315)	—	**2,734**
Share and debt issue costs	669	(56)	(129)	**484**
Non-capital losses	41,965	(4,309)	—	**37,656**
Total deferred tax assets	$ 21,437	$ (9,461)	$ (129)	**$ 11,847**

14. FINANCE EXPENSE

	Three months ended September 30,		Nine months ended September 30,	
	2025	2024	**2025**	2024
Interest on bank debt (note 11)	**$ 1,909**	$ 1,663	**$ 5,406**	$ 3,750
Interest on term loan (note 12)	**580**	372	**1,721**	372
Interest on lease liabilities (note 6)	**79**	—	**239**	—
Total cash finance expense	**2,568**	2,035	**7,366**	4,122
Amortization of debt issue costs (note 12)	**44**	24	**126**	24
Accretion on decommissioning obligations (note 7a)	**282**	75	**811**	208
Accretion on other provision (note 7b)	**114**	—	**366**	—
Total non-cash finance expense	**440**	99	**1,303**	232
Finance expense	**$ 3,008**	$ 2,134	**$ 8,669**	$ 4,354

15. FINANCIAL RISK MANAGEMENT

The following table summarizes the mark to market value of outstanding risk management contract assets (liabilities):

	September 30, 2025	December 31, 2024
Financial oil contracts	**$ 2,592**	$ 3,332
Financial natural gas contracts	**1,407**	6,625
Financial foreign exchange contracts	**191**	(2,735)
Risk management contracts	**$ 4,190**	$ 7,222
Risk management contracts – current asset	**$ 4,690**	$ 9,783
Risk management contracts – non-current asset	**312**	429
Risk management contracts – current liability	**(812)**	(2,765)
Risk management contracts – non-current liability	**—**	(225)
Risk management contracts	**$ 4,190**	$ 7,222

The following table details the gains (losses) on risk management contracts:

	Three months ended September 30,		Nine months ended September 30,	
	2025	2024	**2025**	2024
Unrealized gain (loss) on oil contracts	**$ (1,848)**	$ 11,169	**$ (740)**	$ 2,190
Unrealized loss on natural gas contracts	**(1,998)**	—	**(5,218)**	—
Unrealized gain (loss) on foreign exchange contracts	**(3,598)**	249	**2,926**	(1,094)
Unrealized gain (loss) on risk management contracts	**(7,444)**	11,418	**$ (3,032)**	$ 1,096
Realized gain (loss) on oil contracts	**1,864**	156	**3,861**	(668)
Realized gain on natural gas contracts	**2,149**	—	**5,867**	—
Realized gain (loss) on foreign exchange contracts	**(47)**	12	**(1,127)**	90
Realized gain (loss) on risk management contracts	**3,966**	168	**$ 8,601**	$ (578)
Gain (loss) on risk management contracts	**$ (3,478)**	$ 11,586	**$ 5,569**	$ 518

Oil risk management contracts

At September 30, 2025, the Company had in place the following oil commodity risk management contracts:

Commodity	Volumes Sold (bbl/d)	Term	Reference/Index	Contract Traded Bought/Sold	Average Price ($/bbl)
Crude Oil	1,900 bbl/d	Oct 2025 - Dec 2025	WTI (US$/bbl)	Swap - sold	$67.15
Crude Oil	1,500 bbl/d	Jan 2026 - Mar 2026	WTI (US$/bbl)	Swap - sold	$65.13
Crude Oil	500 bbl/d	Apr 2026 - Dec 2026	WTI (US$/bbl)	Swap - sold	$65.00
Crude Oil	250 bbl/d	Nov 2025 - Dec 2025	WTI (CAD$/bbl)	Swap - sold	$90.03
Crude Oil	1,900 bbl/d	Oct 2025 - Dec 2025	WCS Differential (US$/bbl)	Swap - sold	($14.71)
Crude Oil	250 bbl/d	Nov 2025 - Dec 2025	WCS Differential (CAD$/bbl)	Swap - sold	($16.28)
Crude Oil	200 bbl/d	Oct 2025	WCS (CAD$/bbl)	Swap - sold	$80.00
Crude Oil	950 bbl/d	Nov 2025 - Dec 2025	WCS (CAD$/bbl)	Swap - sold	$74.47

Subsequent to September 30, 2025, the Company entered into the following oil commodity risk management contracts:

Commodity	Volumes Sold (bbl/d)	Term	Reference/Index	Contract Traded Bought/Sold	Average Price ($/bbl)
Crude Oil	1,000 bbl/d	Oct 2025 - Dec 2025	WCS Differential (US$/bbl)	Swap - sold	($11.50)
Crude Oil	1,000 bbl/d	Jan 2026 - Dec 2026	WCS Differential (US$/bbl)	Swap - sold	($12.50)

As at September 30, 2025, if future WTI and WCS oil prices changed by $5.00 per bbl with all other variables held constant, net income and comprehensive income for the period would change by $2.4 million due to changes in the fair value of risk management contracts.

Natural gas risk management contracts

At September 30, 2025, the Company had in place the following natural gas commodity risk management contracts:

Commodity	Volumes Sold	Term	Reference/Index	Contract Traded Bought/Sold	Average Price ($/GJ)
Natural gas (1)	2,500 GJ/d	Oct 2025	AECO 5A (CAD$/GJ)	Swap - sold	$9.01

(1) Inclusive of 15,000 GJ/d sold at $3.19/GJ and a $5.82/GJ realized gain on 12,500 GJ/d of contracted volumes closed out during the period.

As at September 30, 2025, if future AECO gas prices changed by $0.25 per GJ with all other variables held constant, net income and comprehensive income for the year would change by $1.7 million due to changes in the fair value of risk management contracts.

Foreign exchange risk management contracts

At September 30, 2025, the Company had in place the following CAD/USD foreign exchange risk management contracts:

Fixed Contract	Notional amount	Term	Price (CAD$/US$)
Average rate forward (CAD$/US$)	$2,050,000 US$/month	Oct - Dec 2025	1.3763
Average rate forward (CAD$/US$)	$2,500,000 US$/month	Jan - Dec 2026	1.4066
Average rate forward (CAD$/US$)(1)	$5,000,000 US$/month	Jan - Dec 2026	1.3890

(1) At expiry on December 31, 2026 if the calendar 2027 forward strip is above 1.3890 CAD$/US$, Rubellite knocks into a $5.0 million US$/month contract at 1.3890 CAD$/US$ for the 2027 calendar year.

Variable Contract(1)	Notional amount	Term	Floor Price (CAD$/US$)	Ceiling Price (CAD$/US$)	Reset Price (CAD$/US$)
Knock-in Collar (CAD$/US$)	$500,000 US$/month	Oct - Dec 2025	1.3700	1.4375	1.3875
Knock-in Collar (CAD$/US$)	$500,000 US$/month	Oct - Dec 2025	1.3700	1.4300	1.4000

As at September 30, 2025, if future CAD$/US$ exchange rate changed by $0.05 with all other variables held constant, net income and comprehensive income for the year would change by $0.6 million due to changes in the fair value of risk management contracts.

Fair value of financial assets and liabilities

The Company's fair value measurements are classified into one of the following levels of the fair value hierarchy:

Level 1 – inputs represent unadjusted quoted prices in active markets for identical assets and liabilities. An active market is characterized by a high volume of transactions that provides pricing information on an ongoing basis.

Level 2 – inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly. These valuations are based on inputs that can be observed or corroborated in the marketplace, such as market interest rates or forecasted commodity prices.

Level 3 – inputs for the asset or liability are not based on observable market data.

The Company aims to maximize the use of observable inputs when preparing calculations of fair value. Classification of each measurement into the fair value hierarchy is based on the lowest level of input that is significant to the fair value calculation.

The fair value of cash, accounts receivable, and accounts payable and accrued liabilities approximate their carrying amounts due to their short terms to maturity. They are classified at amortized cost, level 1.

The fair value of risk management contracts are classified as fair value through profit or loss ("FVTPL"), level 2.

The fair value of financial assets and liabilities, excluding working capital, is attributable to the following fair value hierarchy levels:

				Fair value		
As of September 30, 2025	**Gross**	**Netting[1]**	**Carrying Amount**	**Level 1**	**Level 2**	**Level 3**
Financial assets						
Fair value through profit and loss						
Risk management contracts	$ 6,301	$ (1,299)	$ 5,002	$ —	$ 5,002	$ —
Financial liabilities						
Financial liabilities at amortized cost						
Bank debt	(90,639)	—	(90,639)	(90,639)	—	—
Term loan	(19,128)	—	(19,128)	(19,128)	—	—
Fair value through profit and loss						
Risk management contracts	(2,111)	1,299	(812)	—	(812)	—

(1) Risk management contract assets and liabilities presented in the consolidated statement of financial position are shown net of offsetting assets or liabilities where the arrangement provides for the legal right and intention for net settlement exists.

CORPORATE INFORMATION

DIRECTORS

Holly A. Benson
Independent Director[(1)(2)(3)]
Linda A. Dietsche
Independent Director[(1)(2)(3)]
Tamara L. MacDonald
Independent Director[(2)(3)(4)]
Geoffrey C. Merritt
Independent Director[(3)(4)(5)]
Susan L. Riddell Rose
President, Chief Executive Officer and Director
Ryan A. Shay
Vice President, Finance and Chief Financial Officer and Director
Bruce C. Shultz
Independent Director[(1)(3)(5)]
Steven L. Spence
Independent Director[(3)(4)(5)]

(1) Member of Audit Committee
(2) Member of Compensation Committee
(3) Member of Corporate Governance Committee
(4) Member of Environmental, Health & Safety Committee
(5) Member of Reserves Committee

OFFICERS

Susan L. Riddell Rose
President, Chief Executive Officer and Director
Ryan A. Shay
Vice President, Finance and Chief Financial Officer
Ryan M. Goosen
Vice President, Business Development and Land
Jeffrey R. Green
Vice President, Corporate and Engineering Services
Marcello M. Rapini
Vice President, Marketing
Karl H. Rumpf
Vice President, Exploration and New Ventures

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AUDITORS

KPMG LLP

BANKERS

ATB Financial
Bank of Montreal
The Bank of Nova Scotia
Shell Trading Canada

RESERVE EVALUATION CONSULTANTS

McDaniel & Associates Consultants Ltd.

REGISTRAR AND TRANSFER AGENT

Odyssey Trust Company