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 six months ended June 30, 2026, 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 six months ended June 30, 2026 as well as the audited consolidated financial statements and accompanying notes for the year ended December 31, 2025. Disclosure, which is unchanged from the December 31, 2025 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 August 7, 2026.

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 heavy crude oil from the Clearwater and Mannville Stack Formations in Eastern Alberta, as well as 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".

QUARTERLY OPERATIONAL AND FINANCIAL HIGHLIGHTS

Operational Highlights

- **Total sales production:** Despite very challenging spring weather conditions, Rubellite averaged total sales production of 13,406 boe/d in the second quarter of 2026 (67% heavy oil and natural gas liquids ("NGL")), exceeding the top end of the quarterly guidance range of 13,300 to 13,400 boe/d. Relative to the 13,843 boe/d (66% heavy oil and NGL) produced in the first quarter of 2026, the 3% decrease reflected natural declines in the West Central area and lower heavy oil sales production.

- **Heavy oil sales production:** Averaged 8,534 bbl/d in the second quarter of 2026, just outside of the quarterly guidance range of 8,550 to 8,650 bbl/d. Relative to the 8,641 bbl/d of sales production in the first quarter of 2026, the 1% decrease reflected downtime related to the challenging conditions in the field and the recess in drilling operations at Frog Lake from February 9, 2026 to April 19, 2026 to allow the drilling rig, which operated continuously for several years, to undergo servicing and recertification. During the quarter, there were 9 (8.5 net) heavy oil wells added to sales at Figure Lake and Frog Lake, with an additional 9 (8.0 net) wells awaiting tie-ins, or recovery of drilling fluids and not yet contributing to sales.

- **Exploration and development spending[(1)]:** Spent $41.0 million in the second quarter, within the guided range of $39.0 to $41.0 million. Second quarter spending included the drilling and completion of 9 (9.0 net) primary open hole multi-lateral ("OHML") Clearwater development wells and 2 (2.0 net) polymer pilot producer-injector pair at Figure Lake; 1 (0.5 net) OHML Waseca South development well, 2 (1.5 net) OHML Waseca North development wells and 2 (1.5 net) GP wells at Frog Lake.

- **Land and geological and geophysical spending:** Spent $2.5 million on land to capture acreage in core areas and for exploration prospects and $0.2 million on geological and geophysical activities related to special core testing to inform enhanced oil recovery pilot work and various data seismic purchases.

- **Asset swap:** On June 30, 2026, Rubellite completed an asset swap transaction that doubled the Company's working interest in its Marten Hills Clearwater assets from 30% to 60%, in exchange for certain non-core undeveloped lands at Dawson and cash consideration of $0.8 million. The incremental 30% working interest represents approximately 191 bbl/d of heavy oil sales production based on second quarter 2026 average rates, which will be reflected in the Company's production volumes beginning in the third quarter of 2026.

- **Abandonment and reclamation:** Spent $0.1 million on decommissioning, abandonment and reclamation activities and received three reclamation certificates from the Alberta Energy Regulator ("AER") in the quarter, bringing the total to four in 2026.

Financial Highlights

- **Adjusted funds flow[(1)]**: $35.2 million ($0.38 per share) in the second quarter of 2026, an increase of 6% from $33.4 million ($0.36 per share) in the first quarter of 2026.

- **Cash costs[(1)]**: $23.5 million or $19.29/boe in the second quarter of 2026, representing a 24% increase on a per boe basis as compared to the first quarter of 2026 (Q1 2026 - $19.4 million or $15.56/boe) driven by increases in net operating costs and transportation costs due to poor lease and road conditions at both Figure Lake and Frog Lake.

- **Net income:** $34.1 million ($0.36 per share) in the second quarter of 2026 primarily driven by an unrealized gain on risk management contracts, reflecting a change in the mark-to-market values of these contracts due to the fluctuation of forward commodity prices.

- **Net debt[(1)]:** $158.1 million at June 30, 2026, an increase of 10% from $143.1 million at December 31, 2025. During the first half of 2026, Rubellite's capital expenditures, including land and other spending, of $76.5 million exceeded adjusted funds flow of $68.6 million. In addition, other obligations were settled, including a $3.8 million reduction of the other provision, $0.5 million of decommissioning expenditures, $0.8 million of cash-settled share based compensation payments and $0.8 million of cash consideration for the asset swap transaction.

- **Available liquidity[(2)]:** During the second quarter, the borrowing limit was increased to $160.0 million from $140.0 million. As at June 30, 2026, available liquidity was $62.9 million, based on the increased $160.0 million first-lien credit facility borrowing limit, less $95.7 million of bank borrowings and $1.4 million in letters of credit.

(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".

Q2 2026 GUIDANCE RECONCILIATION

A comparison of the Company's most recent Q2 2026 guidance metrics to actual results is provided below.

During the second quarter of 2026, Rubellite achieved Q2 2026 total production guidance and grew adjusted funds flow despite extremely challenging spring weather conditions.

- Total sales production exceeded the high end of the guidance range.
- Heavy oil sales production was just outside the low end of its range due to the challenging spring weather conditions.
- Heavy oil wellhead differential of $6.80/bbl was higher than the guided range $5.50 to $6.00/bbl due to higher than expected diluent costs.
- Royalties were 14.9% of revenue, below the guided range of 15.5% to 16.5%.
- Net operating costs of $8.16/boe were higher than the guided range of $6.50 to $7.25/boe, driven by higher road maintenance, trucking and well servicing costs due to extremely wet conditions in the field.
- Transportation costs of $5.58/boe were higher than the guided range of $4.75 to $5.25/boe, driven by higher trucking costs associated with poor road conditions and fuel surcharges on higher gasoline and diesel prices.

	Q2 2026 Guidance(1)	Q2 2026 Actuals
Sales Production (boe/d)	13,300 - 13,400	13,406
Production mix (% oil and NGL)	68%	67%
Heavy oil sales production (bbl/d)	8,550 - 8,650	8,534
Exploration and development spending ($ millions)(2)(3)	$39 - $41	41.0
Heavy oil wellhead differential ($/bbl)(2)	$5.50 - $6.00	$6.80
Royalties (% of revenue)(2)	15.5% - 16.5%	14.9%
Net operating costs ($/boe)(2)	$6.50 - $7.25	$8.16
Transportation costs ($/boe)(2)	$4.75 - $5.25	$5.58
General and administrative costs ($/boe)(2)	$3.00 - $3.50	$3.24

(1) Q2 2026 guidance dated May 8, 2026.
(2) Non-GAAP financial measure, non-GAAP ratio or supplementary financial measure. See "Non-GAAP and Other Financial Measures".
(3) Excludes abandonment and reclamation spending, land and geological expenditures.

OPERATIONS UPDATE

Figure Lake

Primary Development Update:

In the second quarter, Rubellite drilled and rig released 9 (9.0 net) primary OHML development wells targeting the Wabiskaw Member of the Clearwater Formation:

- 4 (4.0 net) at the 12-28-62-18W4 surface pad (the "12-28 Pad")
- 4 (4.0 net) at the 14-22-63-18W4 surface pad (the "14-22 Pad")
- 1 (1.0 net) at the 8-26-61-16W4 surface pad (the "8-26 Pad")

Production results for primary wells drilled to date in 2026 averaged(1) IP30/60 rates of 195 bbl/d (8 wells)/224 bbl/d (5 wells), as compared to the 2025 McDaniel Tier 1 type curve(2) of IP30/60 of 201/193 bbl/d(2).

The well (1.0 net) targeting the Sparky Formation drilled in the fourth quarter of 2025 was brought back on production after spring breakup and continues to deliver at encouraging rates with an IP90 of 230 bbl/d. Continuous production from the initial well and further development of the Sparky discovery pool will require construction of a permanent all season access road. The Sparky pool is located in a Key Wildlife Area as designated by the province with restrictions on field activity in place from January 15th to April 30th. Due to very wet conditions and to lower total costs and to limit impacts to the environment, the permanent road and further development is now planned for the second half of 2027. In the interim, the 8-26-64-18W4 discovery well will continue to be produced to the extent possible using the current temporary access.

Enhanced Oil Recovery ("EOR") Update:

Water injection commenced in March at the first Figure Lake waterflood pilot producer-injector pair drilled in the fourth quarter of 2025 on the 9-35-63-18W4 Pad (the "9-35 Pad"). Early indications are encouraging with inclining production rates and other positive indicators of pressure maintenance observed. A more definitive confirmation of the pilot producer's response to injection support is expected in the fourth quarter of 2026.

The second and third EOR pilots at Figure Lake are both located at the 8-26 Pad, where 8-leg OHML producers are paired with dedicated injectors. The injection wells have initially been configured as producers for a short period to recover the oil-based mud used during drilling, and to create voidage in the reservoir for improved flood front conformance once converted for injection. It is expected that water injection will commence in both injectors in the third quarter of 2026, with polymer injection expected to follow in late 2026 in one of the two injectors.

In addition, two multi-lateral horizontal producer-to-injector conversions were advanced on two separate pads at Figure Lake. These producer-to-injector conversion pilots will evaluate the effectiveness of waterflood where primary-focused multi-lateral drilling development has already occurred.

Information from the multiple EOR pilot schemes is being continuously monitored and evaluated and will inform future development plans.

Frog Lake

Waseca Update - Open Hole Multi-lateral Horizontals:

During the second quarter, Rubellite drilled and rig released 3 (2.0 net) OHML wells targeting the Waseca Formation.

- Waseca North: 2 (1.5 net) extended reach wells (20,000m) were drilled with a new water-based amine mud system. Average[1] IP30/IP60 rates obtained for Waseca North wells drilled to date in 2026 are 105 bbl/d (5 wells)/96 bbl/d (3 wells), as compared to the 2025 McDaniel type curve[2] of 122/117 bbl/d.

- Waseca South: 1 (0.5 net) was drilled in the first quarter of 2026 with average[1] IP30/IP60 rate of 68 bbl/d (1 wells)/ 65 bbl/d (1 well), as compared to the 2025 McDaniel type curve[2] of 145/145 bbl/d. Underperformance for the well drilled in the first quarter is believed to be due to a combination of a thinning reservoir and higher shale content encountered at the toe of the well. A second Waseca South well (0.5 net) drilled in the second quarter has recorded an IP15 of 209 bbl/d.

GP and Sparky Update - Single Leg Lined Laterals with Recycle Strings:

Rubellite has continued to positively advance the use of single leg lined lateral horizontal wells equipped with high velocity recycle strings to enable consistent production of heavy oil with solids from the less consolidated GP and Sparky Sands of the Mannville Stack. Two (1.5 net) GP wells were drilled in the second quarter. Equipping of the wells for production was delayed by wet weather, however both wells were placed on production on July 27th, 2026 and are currently recovering load fluid.

A continuous one-rig drilling program is planned for the remainder of the year, targeting the Waseca North and Waseca South sands with OHML horizontal wells, and the GP and Sparky zones within the Mannville Stack with single leg lined horizontal wells equipped with recycle strings.

Other Exploration

In addition to ongoing zonal delineation activity in the GP and Sparky zones at Frog Lake and the Sparky zone at Figure Lake, Rubellite continued to advance several early-stage exploration prospects including land capture and play concept de-risking, while maintaining a disciplined approach to risked capital exposure. One (1.0 net) exploration well was drilled at Bayhurst, Saskatchewan in the first quarter and placed on a limited production trial paused by the requirement to repair a surface casing vent flow in the well. That repair work was completed in early July, and the well has been placed back on production. A second follow up Bayhurst well (1.0 net) is planned for the fourth quarter of 2026.

(1) No development wells were excluded from the calculation of average results except by the criteria for producing days.
(2) Type curve assumptions are based on the total proved plus probable undeveloped reserves contained in the McDaniel Report as disclosed in the most recent AIF available under the Company's profile on SEDAR+ at www.sedarplus.ca. "McDaniel Report" means the independent engineering evaluation of the heavy crude oil and natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2025 and a preparation date of March 10, 2026.

OUTLOOK AND GUIDANCE

For 2026, Rubellite forecasts total exploration and development spending[1] of $125 to $130 million. In addition to development drilling in its core heavy oil operating areas, Rubellite's 2026 capital spending will support longer term strategic initiatives including: (1) advancing multiple EOR pilots in the Clearwater, with water injection expected to have commenced at six waterflood pilots by the end of the third quarter of 2026; (2) initiating polymer injection on the producer-injector pair drilled for a polymer flood pilot at Figure Lake, with injection planned to commence late in fourth quarter of 2026; (3) additional injection and production cycles under the novel gas injection EOR pilot at Figure Lake; and (4) ongoing exploration activities across the Company's land base.

Forecast Capital Program - Second Half 2026:

At Figure Lake:

- Drilling and completion of 13 (13.0 net) 15,000m, 12 leg, Clearwater primary development wells;
- Equipping and facilities work at the 8-26 Pad in anticipation of water and polymer injection commencing in third and fourth quarters of 2026, respectively;
- Surface and downhole equipping activities related to two mature multi-lateral producer to waterflood injector conversions; and
- Additional core testing to continue to inform EOR initiatives.

At Ukalta:

- Source water management and modification of surface facilities to increase the volume of water available for injection in the recently converted multilateral waterflood injector that commenced injection in the second quarter.

At Frog Lake:

- Drilling and completion of 19 (9.5 net) wells targeting the Waseca North, Waseca South, GP and Sparky zones;
- Drilling and completion of 1 (0.5 net) water disposal well; and
- Coring activity and special core testing to inform EOR initiatives.

Additional capital spending is anticipated for land and seismic purchases and other exploration activities. Capital activity is expected to be funded from adjusted funds flow[1], with any excess free funds flow[1] applied to net debt[1] reduction and other balance sheet obligations.

For 2026, heavy oil sales volumes are forecast to average 8,500 to 9,200 bbl/d, while total production sales volumes, including natural gas and NGL volumes, are forecast to average 13,200 to 13,800 boe/d, representing 6% to 10% growth relative to 2025.

Operating costs are forecast to average $6.75 to $7.25/boe for the second half of 2026, and transportation costs are forecast to average $4.75 to $5.25/boe, reflecting increased fuel surcharges for trucked oil. Heavy oil wellhead differentials are forecast to average $5.25 to $5.75/bbl, assuming diluent pricing consistent with the current forward curve. Royalties are expected to increase as a percentage of revenue, averaging 14.5% to 15.5%, given the higher forecast reference oil prices.

Rubellite will continue to address end of life asset retirement obligations ("ARO"), with $1.3 million of operated abandonment and reclamation expenditures planned for the remainder of 2026. Total abandonment and reclamation spending for 2026 of $1.8 million exceeds the Company's AER area-based mandatory 2026 spending requirement of $1.3 million.

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

Planned exploration and development spending and drilling activity for 2026 is summarized in the table below:

	H1 2026		H2 2026		Full year 2026	
	Capital Expenditures (millions)(1)	**# of wells (*gross/net*)**	**Capital Expenditures (millions)(1)**	**# of wells (*gross/net*)**	**Capital Expenditures (millions)(1)**	**# of wells (*gross/net*)**
Figure Lake(2)		17 / 17.0		13 / 13.0		30 / 30.0
Frog Lake(3)		8 / 6.0		20 / 10.0		28 / 16.0
Marten Hills		-/-		- / -		-/-
East Edson		2 / 1.0		- / -		2 / 1.0
Other Exploration		1 / 1.0		1 / 1.0		2 / 2.0
Total	**$72**	**28 / 25.0**	**$53 - $58**	**34 / 24.0**	**$125 - $130**	**62 / 49.0**

(1) Excludes corporate expenditures, abandonment and reclamation spending, land and geological expenditures, if any.
(2) 2 (2.0 net) wells drilled in Q1 2026 were the waterflood pilot producer-injector pair and 2 (2.0 net) wells drilled in Q2 2026 were the polymer pilot producer-injector pair on the 8-26 Pad at Figure Lake.
(3) Includes 1 (0.5 net) water disposal well which is expected to be drilled in the second half of 2026.

Rubellite's financial and operational guidance for full year 2026 is presented in the table below:

	Previous Full Year 2026 Guidance(1)	Full Year 2026 Guidance
Sales production (boe/d)	13,300 - 13,800	13,200 - 13,800
Production mix (% oil and NGL)	69%	68%
Heavy oil sales production (bbl/d)	8,800 - 9,200	8,500 - 9,200
Exploration and development spending ($ millions)(2)(3)	$125 - $135	$125 - $130
Heavy oil wellhead differential ($/bbl)(2)	$4.50 - $5.50	$5.25 - $5.75
Royalties (% of revenue)(2)	14.5% - 15.5%	14.5% - 15.5%
Net operating costs ($/boe)(2)	$6.50 - $7.00	$6.75 - $7.25
Transportation costs ($/boe)(2)	$4.75 - $5.25	$4.75 - $5.25
General and administrative costs ($/boe)(2)	$3.00 - $3.50	$3.00 - $3.50

(1) Previous full year 2026 guidance dated May 8, 2026.
(2) Non-GAAP financial measure, non-GAAP ratio or supplementary financial measure. See "Non-GAAP and Other Financial Measures".
(3) Excludes abandonment and reclamation spending, land and geological expenditures, if any.

SECOND QUARTER 2026 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, it 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 June 30,					
	2026			2025		
(*$ thousands*)	**E&E**	**PP&E**	**Total**	E&E	PP&E	Total
Drilling and completions	**401**	**35,756**	**36,157**	7	19,619	19,626
Facilities	**(33)**	**4,870**	**4,837**	38	4,133	4,171
Exploration and development spending(1)	**368**	**40,626**	**40,994**	45	23,752	23,797
Land	**2,333**	**128**	**2,461**	2,830	3,943	6,773
Geological and geophysical ("G&G")	**235**	**—**	**235**	542	—	542
Corporate and other	**—**	**193**	**193**	—	56	56
Total capital expenditures(1)	**2,936**	**40,947**	**43,883**	3,417	27,751	31,168

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

	Six months ended June 30,					
	2026			2025		
(*$ thousands*)	**E&E**	**PP&E**	**Total**	E&E	PP&E	Total
Drilling and completions	**3,038**	**56,464**	**59,502**	1,037	37,557	38,594
Facilities	**634**	**12,203**	**12,837**	267	7,219	7,486
Exploration and development spending(1)	**3,672**	**68,667**	**72,339**	1,304	44,776	46,080
Land	**2,882**	**437**	**3,319**	4,099	4,777	8,876
Geological and geophysical ("G&G")	**353**	**250**	**603**	947	—	947
Corporate and other	**—**	**286**	**286**	—	197	197
Total capital expenditures(1)	**6,907**	**69,640**	**76,547**	6,350	49,750	56,100

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

Exploration and Development Spending by cash-generating unit ("CGU")

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	**2026**	2025	**2026**	2025
Eastern Heavy Oil	**39,717**	23,554	**65,883**	45,256
West Central	**1,277**	243	**6,456**	824
Exploration and development spending(1)	**40,994**	23,797	**72,339**	46,080

(1) Excludes land, geological and geophysical, corporate and other capital expenditures; Non-GAAP measure. See "Non-GAAP and Other Financial Measures".

Wells drilled by area

	Three months ended June 30,		Six months ended June 30,	
(gross/net)	**2026**	2025	**2026**	2025
Development				
Figure Lake(1)(3)(4)	**11 / 11.0**	5 / 5.0	**17 / 17.0**	9 / 9.0
Frog Lake(2)	**5 /3.5**	6 / 4.0	**8 / 6.0**	12 / 8.5
Marten Hills waterflood injection(5)	**-/-**	- / -	**-/-**	1 / 0.3
Edson	**-/-**	- / -	**2 / 1.0**	- / -
Exploration				
Other exploratory(6)	**- / -**	- / -	**1 / 1.0**	1 / 1.0
Total	**16 / 14.5**	11 / 9.0	**28 / 25.0**	23 / 18.8

(1) 2 (2.0 net) wells drilled at Figure Lake were spud at the end of June 2026 and rig released mid-July 2026 and not included in the Q2 2026 well count.
(2) 1 (0.5 net) well drilled at Frog Lake was spud at the end of June 2026 and rig released early July 2026 and not included in the Q2 2026 well count.
(3) 2 (2.0 net) wells drilled in Q1 2026 at Figure Lake were the waterflood pilot 8-leg producer and single-leg injector on the 8-26 Pad at Figure Lake.
(4) 2 (2.0 net) wells drilled in Q2 2026 at Figure Lake were the polymer flood pilot 8-leg producer and single-leg injector on the 8-26 Pad at Figure Lake.
(5) 1 (0.3 net) injection waterflood well was drilled at Marten Hills on the 12-35 Pad during Q1 2025.
(6) 1 (1.0 net) horizontal evaluation well was drilled in Q1 2026 and the costs remain in E&E on the balance sheet. 1 (1.0 net) evaluation well was drilled in Q1 2025 and the costs associated were transferred to E&E expense in Q1 2025.

Capital Expenditures

During the second quarter of 2026, the Company spent $41.0 million on exploration and development activities, before land, geological and geophysical, corporate and other spending (Q2 2025 - $23.8 million). Capital activities in the second quarter included the following:

At Figure Lake, the Company drilled 11 (11.0 net) wells and completed and brought on production 6 (6.0 net) wells.

- Drilled and completed 9 (9.0 net) OHML wells on the 8-26 Pad, the 12-28 Pad and the 14-22 Pad targeting development of the Clearwater formation using the Company's standard 15,000m primary well design;
- Drilled and completed 1 (1.0 net) pilot polymer flood producer and 1 (1.0 net) injector on the 8-26 Pad;
- A portion of capital to drill 2 (2.0 net) additional wells on the 12-28 Pad and 14-22 Pad was spent during the second quarter and the wells were rig released early in the third quarter of 2026; and
- Facilities spending included $3.6 million on the 12-28 and 14-22 Pads and field modifications related to several enhanced oil recovery pilot projects.

At Frog Lake, the Company drilled 5 (3.5 net) wells and completed and brought on production 3 (2.5 net) wells.

- Drilled and completed 1 (0.5 net) OHML well targeting the development of the Waseca South formation;
- Drilled and completed 2 (1.5 net) OHML wells targeting the development of the Waseca North formation;
- Drilled and completed 2 (1.5 net) wells targeting the GP formation;
- A portion of capital to drill 1 (0.5 net) additional well on the 2-15 Pad was spent during the second quarter and was rig released early in the third quarter of 2026; and
- Facilities spending included $1.2 million on three new pad sites.

During the first six months of 2026, the Company spent $72.3 million on exploration and development activities, before land and other corporate spending, primarily related to the drill, complete, equip and tie-in of the following:

- 13 (13.0 net) multi-lateral horizontal wells at Figure Lake;
- 1 (1.0 net) waterflood pilot producer and 1 (1.0 net) injector at Figure Lake;
- 1 (1.0 net) polymer pilot flood producer and 1 (1.0 net) injector at Figure Lake;
- 2 (1.0 net) Waseca South development wells at Frog Lake;
- 4 (3.5 net) Waseca North development wells at Frog Lake;
- 2 (1.5 net) GP wells at Frog Lake;
- 2 (1.0 net) Wilrich natural gas development wells at East Edson: and
- 1 (1.0 net) exploratory evaluation well in southwest Saskatchewan

Land spending totaled $2.5 million in the second quarter of 2026, with total spending in the first half of 2026 of $3.3 million to capture acreage in core areas and for exploration prospects (Q2 2025 - $6.8 million; 2025 - $8.9 million). Geological and geophysical spending totaled $0.2 million in the second quarter of 2026, with total spending of $0.6 million in the first half of 2026 (Q2 2025 - $0.5 million; 2025 - $0.9 million), primarily for data seismic data purchases and for special core analyses to advance enhanced oil recovery at Figure Lake.

Rubellite spent $0.1 million (Q2 2025 - $0.1 million) on abandonment and reclamation projects, with total asset retirement obligation expenditures of $0.5 million (2025 - $0.9 million) in the first half of 2026 and received three reclamation certificates from the AER in the second quarter of 2026, bringing the total to four in 2026 (Q2 2025 - one certificate; 2025 - two certificates).

Sales Production

	Three months ended June 30,		Six months ended June 30,	
	2026	2025	**2026**	2025
Sales volumes				
Heavy oil (bbl/d)	**8,534**	8,637	**8,588**	8,489
Natural gas (Mcf/d)	**26,576**	20,522	**27,549**	21,276
NGL (bbl/d)	**443**	368	**445**	370
Total sales volumes (boe/d)	**13,406**	12,425	**13,625**	12,405

Sales production for the three and six months ended June 30, 2026 by CGU:

	Three months ended June 30,		Six months ended June 30,	
	2026	2025	**2026**	2025
Sales volumes by CGU				
Eastern Heavy Oil (boe/d)	**9,521**	9,157	**9,575**	8,918
West Central (boe/d)	**3,885**	3,268	**4,050**	3,487
Total sales volumes (boe/d)	**13,406**	12,425	**13,625**	12,405

Total sales production for the three and six months ended June 30, 2026 increased by 981 boe/d (8%) and 1,220 boe/d (10%) from the comparative periods of 2025, reflecting the Company's heavy oil drilling program and increased solution gas conservation at the Figure Lake gas plant. Despite extremely challenging wet spring weather conditions, the Company exceeded the quarterly total sales production guidance range of 13,300 to 13,400 boe/d (13,406 boe/d).

Heavy oil sales production averaged 8,534 bbl/d and 8,588 bbl/d for the three and six months ended June 30, 2026, a 1% change from the comparative periods of 2025 (Q2 2025 - 8,637 bbl/d; 2025 - 8,489 bbl/d), and just outside of the guidance range of 8,550 to 8,650 bbl/d. The decrease in the second quarter was primarily the result of extremely poor weather conditions in the field, which impacted production with downtime related to well servicing delays and the trucking of heavy oil volumes to sales points. During the second quarter of 2026, 9 (8.5 net) heavy oil wells were added to sales, with an additional 9 (8.0 net) wells awaiting tie-ins, or recovery of drilling fluids and not yet contributing to sales.

Natural gas production averaged 26.6 MMcf/d and 27.5 MMcf/d for the three and six months ended June 30, 2026, an increase of 30% and 29% from the comparative periods of 2025 (Q2 2025 - 20.5 MMcf/d; 2025 - 21.3 MMcf/d). In the West Central area, 2 (1.0 net) liquids-rich natural gas wells were brought on production at the end of the fourth quarter of 2025, followed by 2 (1.0 net) additional wells during the first quarter of 2026. In addition, the Figure Lake gas plant contributed an average of 5.8 MMcf/d of solution gas sales during the three and six months ended June 30, 2026, as compared to 3.0 MMcf/d and 2.5 MMcf/d of solution gas sales in the comparative periods of 2025.

During the three and six months ended June 30, 2026, NGL production averaged 443 bbl/d and 445 bbl/d, an increase from the comparative periods of 2025, which was consistent with the increase in natural gas volumes.

Rubellite's sales product mix, based on sales production, averaged 67% heavy oil and NGL and 33% natural gas during the second quarter (Q2 2025 - 72% heavy oil and NGL and 28% natural gas), reflecting increased solution gas conservation at Figure Lake and the timing of East Edson drilling activities. The first half of 2026 sales production mix averaged 66% heavy oil and NGL and 34% natural gas (2025 comparative periods - 71% and 29%).

Revenue

	Three months ended June 30,		Six months ended June 30,	
($ thousands, except as noted)	**2026**	2025	**2026**	2025
Oil and natural gas revenue				
Oil	**78,572**	55,002	**136,447**	115,063
Natural gas	**4,190**	3,598	**10,020**	7,888
NGL	**3,301**	1,942	**5,839**	4,198
Oil and natural gas revenue	**86,063**	60,542	**152,306**	127,149
Reference prices				
West Texas Intermediate (WTI) (US$/bbl)	**92.79**	63.74	**82.36**	67.58
Foreign Exchange rate (CAD$/US$)	**1.38**	1.38	**1.38**	1.41
WTI (CAD$/bbl)	**128.05**	87.96	**113.66**	95.29
Western Canadian Select (WCS) differential (US$/bbl)	**(14.66)**	(10.27)	**(14.41)**	(11.47)
WCS (CAD$/bbl)	**107.97**	73.96	**93.60**	79.13
Heavy oil wellhead differential (CAD$/bbl)(3)	**6.80**	3.98	**5.82**	4.24
AECO 5A Daily Index (CAD$/GJ)	**1.59**	1.60	**1.74**	1.83
AECO 5A Daily Index (CAD$/Mcf)(1)	**1.68**	1.69	**1.84**	1.93
Rubellite average realized prices(2)(3)				
Oil ($/bbl)	**101.17**	69.98	**87.78**	74.89
Natural gas ($/Mcf)	**1.73**	1.93	**2.01**	2.05
NGL ($/bbl)	**81.97**	57.92	**72.54**	62.72
Average realized price ($/boe)(2)(3)	**70.54**	53.54	**61.77**	56.63

(1) Converted from $/GJ using a standard energy conversion rate of 1.06 GJ:1 Mcf.
(2) Average prices are presented before risk management contracts;
(3) Supplementary financial measure. See "Non-GAAP and Other Financial Measures".

Rubellite’s oil and natural gas revenue for the three and six months ended June 30, 2026 increased by $25.5 million, or 42%, and $25.2 million, or 20%, from the comparative periods of 2025, primarily driven by higher oil prices.

Oil revenue for the second quarter of 2026 was $78.6 million, representing 91% of total revenue, while heavy oil production was 64% of total sales volumes. The 43% increase in oil revenue was driven by a 45% increase in average realized oil prices. The WCS price averaged $107.97/bbl in the second quarter (Q2 2025 - $73.96/bbl), reflecting higher WTI oil prices of US$92.79/bbl (2025 - US$63.74/bbl), partially offset by the widening of the WCS differential to US$14.66/bbl (Q2 2025 - US$10.27/bbl). Rubellite's heavy oil wellhead differential, which reflects a price offset for quality, diluent blending costs and optimization of sales delivery points, averaged $6.80/bbl during the second quarter of 2026 (Q2 2025 - $3.98/bbl), and was higher than the guided range of $5.50 to $6.00/bbl due to higher diluent costs.

During the first half of 2026, oil revenue was $136.4 million and represented 90% of total revenue while heavy oil production was 63% of total sales volumes. The 19% increase in oil revenue was driven by the increase in average realized oil prices. Higher WCS prices were driven by an increase in WTI oil prices to US$82.36/bbl (2025 - US$67.58/bbl), partially offset by a decrease in the CAD$/US$ rate to $1.38 (2025 - $1.41) and the widening of the WCS differential to US$14.41/bbl (2025 - US$11.47/bbl). Rubellite's heavy oil wellhead differential averaged $5.82/bbl for the first half of 2026, as compared to $4.24/bbl in the comparative period of 2025, reflecting higher diluent costs.

Natural gas revenue in the second quarter of 2026 was $4.2 million, representing 5% of total revenue, while natural gas production accounted for 33% of total sales volumes. For the six months ended June 30, 2026, natural gas revenue was $10.0 million and 7% of total revenue while natural gas production was 34% of total sales volumes. For the three and six months ended June 30, 2026, the increase in natural gas revenue was driven by higher natural gas sales volumes, partially offset by lower AECO Daily Index prices.

NGL revenue was $3.3 million in the second quarter of 2026, representing 4% of total revenue and 3% of total sales volumes. The 70% increase in NGL revenue was driven by a 42% increase in average realized NGL prices and a 20% increase in NGL sales volumes. For the six months ended June 30, 2026, NGL revenue of $5.8 million represented 4% of total revenue and 3% of total sales volumes.

Risk Management Contracts

The Company uses “average realized prices after risk management contracts” which is not a standardized measure; 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 June 30,		Six months ended June 30,	
(*$ thousands, except as noted*)	**2026**	2025	**2026**	2025
Unrealized gain (loss) on risk management contracts				
Unrealized gain (loss) on oil contracts(1)	**36,950**	12,651	**6,184**	7,631
Unrealized gain (loss) on natural gas contracts	**(535)**	(632)	**269**	(3,219)
Unrealized gain (loss) on risk management contracts	**36,415**	12,019	**6,453**	4,412
Realized gain (loss) on risk management contracts				
Realized gain (loss) on oil contracts(1)	**(15,057)**	2,945	**(20,110)**	918
Realized gain (loss) on natural gas contracts	**611**	1,878	**924**	3,717
Realized gain (loss) on risk management contracts	**(14,446)**	4,823	**(19,186)**	4,635

(1) 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 June 30,		Six months ended June 30,	
	2026	2025	**2026**	2025
Realized gain (loss) on risk management contracts				
Realized loss on oil contracts ($/bbl)(1)	**(19.39)**	3.75	**(12.94)**	0.60
Realized gain on natural gas contracts ($/Mcf)	**0.25**	1.01	**0.19**	0.97
Realized loss on risk management contracts ($/boe)	**(11.84)**	4.27	**(7.78)**	2.06
Average realized prices after risk management contracts(2)				
Oil ($/bbl)	**81.78**	73.73	**74.84**	75.49
Natural gas ($/Mcf)	**1.98**	2.94	**2.20**	3.02
NGL ($/bbl)	**81.97**	57.92	**72.54**	62.72
Average realized price ($/boe)(2)	**58.70**	57.81	**53.99**	58.69

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

The realized loss on risk management contracts was $14.4 million, or $11.84/boe, for the second quarter of 2026 (Q2 2025 - realized gain of $4.8 million, or $4.27/boe). For the six month period ending June 30, 2026, the realized loss on risk management contracts totaled $19.2 million or $7.78/boe (2025 - realized gain of $4.6 million or $2.06/boe). Realized gains or losses reflect 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.

The unrealized gain on risk management contracts was $36.4 million in the second quarter of 2026 (Q2 2025 – $12.0 million unrealized gain) and the unrealized gain on risk management contracts was $6.5 million for the six month period ended June 30, 2026 (2025 - $4.4 million unrealized gain). Unrealized gains and losses reflect the period end change in the mark-to-market value of risk management contracts, driven by movements in forward commodity prices and foreign exchange rates. 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 June 30,		Six months ended June 30,	
(*$ thousands, except as noted*)	**2026**	2025	**2026**	2025
Royalty expenses	**12,843**	7,631	**21,593**	17,080
$/boe	**10.53**	6.75	**8.76**	7.61
Royalties *(% of revenue)(1)*	**14.9**	12.6	**14.2**	13.4

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

Royalties payable by the Company include Crown royalties payable to provincial governments, royalties payable to Indian Oil and Gas Canada ("IOGC") and freehold and gross overriding royalties ("GORR"). The relative mix between Crown, IOGC, freehold and GORR 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") and the Indian Oil and Gas Act, Crown and IOGC royalties range from 5% to 40% on wells where mineral rights are leased from either the Crown or through IOGC. The remainder of royalties relate to freehold and GORR interests. All royalty rates paid by the Company are price sensitive and fluctuate with commodity pricing.

Total royalties for the three and six months ended June 30, 2026 were $12.8 million and $21.6 million, an increase from the comparative periods of 2025, reflecting higher oil and NGL prices and higher total production volumes. During the second quarter of 2026, the Company received its annual gas cost allowance ("GCA") adjustment, which was a payable of $0.2 million (2025 - $1.0 million credit).

On a per boe basis, royalties were $10.53/boe and $8.76/boe, an increase from the comparative periods of 2025, driven by higher prices. Royalties as a percentage of revenue were higher than the comparative periods of 2025 due to an increased number of wells receiving higher royalty rates due to the significantly higher prices. In the second quarter of 2026, royalties as a percentage of revenue were 14.9%, below the guided range of 15.5% to 16.5% due to lower oil royalty reference par prices, which trail actual prices by two months in arrears.

Net operating costs(1)

	Three months ended June 30,		Six months ended June 30,	
(*$ thousands, except as noted*)	**2026**	2025	**2026**	2025
Net operating costs(1)	**9,949**	7,591	**17,284**	15,387
$/boe	**8.16**	6.71	**7.01**	6.85

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

Total net operating costs for the three and six months ended June 30, 2026 increased to $9.9 million and $17.3 million from $7.6 million and $15.4 million in the comparative periods of 2025, driven by higher road maintenance, trucking and well servicing costs at the heavy oil properties due to extremely wet conditions in the field.

On a per boe basis, net operating costs increased by 22% to $8.16/boe in the second quarter of 2026 (Q2 2025 - $6.71/boe) and were higher than the guided range of $6.50 to $7.25/boe, reflecting the higher costs due to extremely wet road and lease conditions in the field. For the six months ended June 30, 2026, net operating costs on a per boe basis increased 2% to $7.01/boe (2025 - $6.85/boe), driven by the weather related cost increases in the second quarter.

Transportation costs

	Three months ended June 30,		Six months ended June 30,	
(*$ thousands, except as noted*)	**2026**	2025	**2026**	2025
Oil and NGL transportation costs	**6,110**	6,085	**10,942**	11,707
Natural gas transportation costs	**692**	622	**1,490**	1,231
Total transportation costs	**6,802**	6,707	**12,432**	12,938
$/boe	**5.58**	5.93	**5.04**	5.76

Transportation costs include clean oil trucking, NGL transportation and natural gas transportation from plant gate to commercial sales points. Transportation costs for the three months ended June 30, 2026 increased to $6.8 million from $6.7 million in the comparative period of 2025 on higher natural gas and NGL sales production, offset by the 1% decrease in heavy oil sales production volumes which incurred higher transportation costs due to the poor weather and fuel surcharges on higher gasoline and diesel prices. During the first half of 2026, transportation costs decreased to $12.4 million from $12.9 million in the comparative period of 2025 as a result of lower overall trucking rates more than offsetting increased trucking activity related to higher heavy oil sales production and increased fuel surcharges.

On a per boe basis, transportation costs were $5.58/boe in the second quarter of 2026, a 6% decrease from the comparative period (Q2 2025 - $5.93/boe), and higher than the guided range of $4.75/boe to $5.25/boe due to the same reasons noted above. For the first half of 2026, transportation costs were $5.04/boe, 13% lower than the comparative period of 2025 (2025 - $5.76/boe). The reductions were driven by improved trucking rates and fixed natural gas transportation commitments being allocated over higher sales volumes. The reductions in trucking rates were partially offset by increased trucking costs related to poor road conditions and higher fuel surcharges.

Operating netbacks

The following tables highlight Rubellite's operating netbacks for the three and six months ended June 30, 2026 and 2025**:**

	Three months ended June 30, 2026			Three months ended June 30, 2025		
($ thousands)	**Eastern Heavy Oil**	**West Central**	**Total**	Eastern Heavy Oil	West Central	Total
Revenue	**79,584**	**6,479**	**86,063**	55,753	4,789	60,542
Royalties	**(11,443)**	**(1,400)**	**(12,843)**	(7,666)	35	(7,631)
Net operating costs[1]	**(8,755)**	**(1,194)**	**(9,949)**	(5,638)	(1,953)	(7,591)
Transportation costs	**(6,146)**	**(656)**	**(6,802)**	(6,167)	(540)	(6,707)
Operating netback[1]	**53,240**	**3,229**	**56,469**	36,282	2,331	38,613
Realized gain (loss) on risk management contracts[2]	**—**	**—**	**(14,446)**	—	—	4,823
Total operating netback, after risk management contracts[1]	**53,240**	**3,229**	**42,023**	36,282	2,331	43,436

(1) Non-GAAP measure. See "Non-GAAP and Other Financial Measures".
(2) Realized loss on risk management contracts in the second quarter of 2026 included a $15.1 million loss on oil contracts and $0.6 million gain on gas contracts (Q2 2025 - $2.9 million gain on oil contracts and $1.9 million gain on gas contracts).

	Six months ended June 30, 2026			Six months ended June 30, 2025		
($ thousands)	**Eastern Heavy Oil**	**West Central**	**Total**	Eastern Heavy Oil	West Central	Total
Revenue	**138,656**	**13,650**	**152,306**	116,045	11,104	127,149
Royalties	**(19,385)**	**(2,208)**	**(21,593)**	(15,789)	(1,291)	(17,080)
Net operating costs[1]	**(14,965)**	**(2,319)**	**(17,284)**	(11,732)	(3,655)	(15,387)
Transportation costs	**(11,115)**	**(1,317)**	**(12,432)**	(11,769)	(1,169)	(12,938)
Operating netback[1]	**93,191**	**7,806**	**100,997**	76,755	4,989	81,744
Realized gain (loss) on risk management contracts[2]	**—**	**—**	**(19,186)**	—	—	4,635
Total operating netback, after risk management contracts[1]	**93,191**	**7,806**	**81,811**	76,755	4,989	86,379

(1) Non-GAAP measure. See "Non-GAAP and Other Financial Measures".
(2) Realized loss on risk management contracts in the first half of 2026 included a $20.4 million loss on oil contracts and $0.9 million gain on gas contracts (2025 - $0.9 million gain on oil contracts and $3.7 million gain on gas contracts).

	Three months ended June 30, 2026			Three months ended June 30, 2025		
($/boe)	**Eastern Heavy Oil**	**West Central**	**Total**	Eastern Heavy Oil	West Central	Total
Revenue	**91.86**	**18.32**	**70.54**	66.90	16.10	53.54
Royalties	**(13.21)**	**(3.96)**	**(10.53)**	(9.20)	0.12	(6.75)
Net operating costs[1]	**(10.11)**	**(3.38)**	**(8.16)**	(6.35)	(6.57)	(6.71)
Transportation costs	**(7.09)**	**(1.86)**	**(5.58)**	(7.40)	(1.82)	(5.93)
Operating netback[1]	**61.45**	**9.12**	**46.27**	43.95	7.83	34.15
Realized gain (loss) on risk management contracts[2]	**—**	**—**	**(11.84)**	—	—	4.27
Total operating netback, after risk management contracts[1]	**61.45**	**9.12**	**34.43**	43.95	7.83	38.42

(1) Non-GAAP measure. See "Non-GAAP and Other Financial Measures".
(2) Realized loss on risk management contracts in the second quarter of 2026 included a $19.39/bbl loss on oil contracts and a $0.25/Mcf gain on gas contracts (Q2 2025 - $3.75/bbl gain on oil contracts and $1.01/Mcf gain on gas contracts).

	Six months ended June 30, 2026			Six months ended June 30, 2025		
($/boe)	**Eastern Heavy Oil**	**West Central**	**Total**	Eastern Heavy Oil	West Central	Total
Revenue	**80.01**	**18.62**	**61.77**	71.89	17.59	56.63
Royalties	**(11.19)**	**(3.01)**	**(8.76)**	(9.78)	(2.05)	(7.61)
Net operating costs[1]	**(8.64)**	**(3.16)**	**(7.01)**	(7.06)	(5.79)	(6.85)
Transportation costs	**(6.41)**	**(1.80)**	**(5.04)**	(7.29)	(1.85)	(5.76)
Operating netback[1]	**53.77**	**10.65**	**40.96**	47.76	7.90	36.41
Realized gain (loss) on risk management contracts[2]	**—**	**—**	**(7.78)**	—	—	2.06
Total operating netback, after risk management contracts[1]	**53.77**	**10.65**	**33.18**	47.76	7.90	38.47

(1) Non-GAAP measure. See "Non-GAAP and Other Financial Measures".
(2) Realized hedging for the first six months of 2026 included a $12.94/bbl loss on oil contracts and a $0.19/Mcf gain on gas contracts (2025 - $0.60/bbl gain on oil contracts and $0.97/Mcf gain on gas contracts).

Rubellite's Eastern Heavy Oil operating netback for the three and six months ended June 30, 2026 increased to $53.2 million and $93.2 million (Q2 2025 - $36.3 million; 2025 - $76.8 million) as a result of higher realized oil prices and lower transportation costs, partially offset by higher royalties and net operating costs. On a per boe basis, the operating netback increased to $61.45/boe and $53.77/boe (Q2 2025 - $43.95/boe; 2025 - $47.76/boe), reflecting higher realized prices and lower transportation costs, partially offset by higher royalties and net operating costs.

Rubellite's West Central operating netback for the three and six months ended June 30, 2026 increased to $3.2 million and $7.8 million (Q2 2025 - $2.3 million; 2025 - $5.0 million) as a result of higher sales volumes. On a per boe basis, the West Central operating netback in the second quarter of 2026 increased to $9.12/boe (Q2 2025 - $7.83/boe), reflecting higher realized NGL prices and lower net operating costs, partially offset by higher royalties and transportation. In 2026, the West Central operating netback on a per boe basis increased to $10.65/boe (2025 - $7.90/boe), reflecting higher realized prices and lower net operating and transportation costs, partially offset by higher royalties.

Rubellite's total operating netback for the three and six months ended June 30, 2026 increased to $56.5 million and $101.0 million from $38.6 million and $81.7 million in the comparative periods of 2025. On a per boe basis, the operating netback increased, reflecting higher total sales volumes, higher realized oil and NGL prices and lower transportation costs, partially offset by higher royalties and net operating costs.

For the three and six months ended June 30, 2026, the operating netback after realized losses on risk management contracts of $11.84/boe and $7.78/boe, was $34.43/boe and $33.18/boe (Q2 2025 – $38.42/boe; 2025 - $38.47/boe; after realized gains on risk management contracts).

General and administrative ("G&A") expenses

	Three months ended June 30,		Six months ended June 30,	
(*$ thousands, except as noted*)	**2026**	2025	**2026**	2025
G&A expenses – before recoveries	**5,495**	5,084	**11,487**	10,727
G&A recoveries	**(1,547)**	(1,069)	**(3,206)**	(2,298)
Total G&A expenses	**3,948**	4,015	**8,281**	8,429
$/boe	**3.24**	3.55	**3.36**	3.75

Before overhead recoveries, G&A expenses for the three and six months ended June 30, 2026 increased to $5.5 million and $11.5 million (Q2 2025 – $5.1 million; 2025 - $10.7 million), primarily due to higher people-related costs. Total G&A expenses, net of recoveries, were $4.0 million and $8.3 million, consistent with the comparative periods of 2025 (Q2 2025 - $4.0 million; 2025 - $8.4 million), as higher overhead recoveries related to increased capital activity offset the increase in gross costs. Overhead recoveries vary from period to period based on the amount of capital expenditures incurred.

On a per boe basis, G&A costs for the three and six months ended June 30, 2026 decreased to $3.24/boe and $3.36/boe (Q2 2025 - $3.55/boe; 2025 - $3.75/boe), with the second quarter within the guided range of $3.00 to $3.50/boe. The decrease on a per boe basis reflects higher overhead recoveries on higher capital spending and the growth in total sales volumes relative to the comparative periods of 2025.

Depletion

	Three months ended June 30,		Six months ended June 30,	
(*$ thousands, except as noted*)	**2026**	2025	**2026**	2025
Depletion	**24,716**	23,669	**49,086**	45,326
Depreciation	**555**	505	**1,094**	1,010
Total depletion and depreciation	**25,271**	24,174	**50,180**	46,336
($/boe)				
Depletion	**20.26**	20.93	**19.91**	20.19
Depreciation	**0.45**	0.45	**0.44**	0.45
$/boe	**20.71**	21.38	**20.35**	20.64

The Company calculates depletion using the net book value of the assets, future development costs associated with proved and probable reserves, salvage values on associated production equipment, as well as proved plus probable reserves and sales production. As at June 30, 2026, depletion was calculated on a $544.8 million depletable balance (December 31, 2025 – $514.8 million), $415.7 million in future development costs (December 31, 2025 – $457.6 million) and excluded an estimated $12.5 million of salvage value (December 31, 2025 – $12.4 million).

Depletion and depreciation expense for the second quarter of 2026 was $25.3 million or $20.71/boe (Q2 2025 – $24.2 million or $21.38/boe) and $50.2 million or $20.35/boe for the first half of 2026 (2025 - $46.3 million or $20.64/boe). The increase in depletion on a dollar basis was primarily due to higher depletion rates in the Company's West Central CGU, as production levels increased while reserve additions were limited, reflecting the conversion of existing probable locations into producing locations rather than new reserves. On a per boe basis, depletion was lower due to higher reserves relative to production in the Eastern Heavy Oil CGU.

Depletion will fluctuate from one period to the next depending on the amount of capital spent, reserve additions and production volumes.

Impairment

Eastern Heavy Oil CGU

The Company assessed its Eastern Heavy Oil CGU for indicators of impairment as at June 30, 2026 and December 31, 2025, and concluded there were no indicators of impairment, therefore an impairment test was not required.

West Central CGU

The Company assessed its West Central CGU for indicators of impairment as at June 30, 2026, and concluded there were no indicators of impairment, therefore an impairment test was not required.

At December 31, 2025, the Company completed an assessment to determine if indicators of impairment existed within the West Central CGU. As a result of the assessment, the Company determined that indicators of impairment existed at December 31, 2025 as the carrying amount of the CGU may exceed the recoverable amount. The Company performed the required impairment test using the value-in use ("VIU") approach incorporating benchmark pricing based on the average of the three independent reserve evaluators' forecast and utilizing a discount rate of 15%. The test determined that the recoverable amount of the West Central CGU exceeded its carrying value as at December 31, 2025 and as a result, no impairment was recognized.

Finance expense

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	**2026**	2025	**2026**	2025
Cash finance expense				
Interest on bank debt	**2,032**	1,687	**3,475**	3,498
Interest on term loan	**573**	573	**1,141**	1,140
Interest on other provision	**144**	—	**144**	—
Interest on lease liabilities	**75**	79	**152**	160
Total cash finance expense	**2,824**	2,339	**4,912**	4,798
$/boe	**2.31**	2.07	**1.99**	2.14
Non-cash finance expense				
Amortization of debt issue costs	**47**	41	**92**	81
Accretion on decommissioning obligations	**350**	264	**693**	529
Accretion on other provision	**88**	114	**202**	253
Total non-cash finance expense	**485**	419	**987**	863
$/boe	**0.40**	0.37	**0.40**	0.38
Finance expense	**3,309**	2,758	**5,899**	5,661

Total cash finance expense for the three and six months ended June 30, 2026 increased to $2.8 million and $4.9 million (Q2 2025 - $2.3 million; 2025 - $4.8 million) primarily due to renewal fees incurred during the quarter related to the increase in the credit facility and interest on the other provision, partially offset by lower interest rates. The effective aggregate interest rate on the Company's revolving bank line averaged 5.9% and 5.7% (Q2 2025 - 6.3%; 2025 - 6.0%) and the interest rate on the principal amount of the term loan remained unchanged at 11.5%. The other provision began accruing interest as of March 28, 2026 at 4.5%, reflecting the Bank of Canada prime rate.

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

For the three months ended June 30, 2026, cash finance expense on a per boe basis increased as the higher costs outpaced the growth in sales volumes. In the first half of 2026, cash finance expense on a per boe basis decreased as higher costs were offset by higher sales volumes.

Deferred Income Taxes

	December 31, 2025	Recognized in earnings	Recognized in equity	**June 30, 2026**
Deferred tax assets (liabilities):				
Property, plant and equipment	$ (38,100)	$ (4,424)	$ —	**$ (42,524)**
Decommissioning obligations	8,198	459	—	**8,657**
Fair value of derivatives	(1,265)	(1,484)	—	**(2,749)**
Other liabilities	2,820	(749)	—	**2,071**
Share and debt issue costs	414	(46)	(65)	**303**
Non-capital losses	40,313	1,689	—	**42,002**
Deferred tax asset	$ 12,380	$ (4,555)	$ (65)	**$ 7,760**

Deferred income tax expense was $10.9 million for the three months ended June 30, 2026, an increase from $6.9 million for the comparative period of 2025 due to unrealized hedging gains. For the six months ended June 30, 2026, deferred income tax expense decreased to $4.6 million from $7.7 million in 2025, reflecting lower earnings, driven by realized hedging losses on commodity risk management contracts.

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*)	**June 30, 2026**	December 31, 2025
Bank debt	**95,660**	92,583
Term loan (principal)	**20,000**	20,000
Adjusted working capital deficit(1)	**42,416**	30,560
Net debt(1)	**158,076**	143,143
Shares outstanding at end of period (*thousands*)	**93,942**	93,593
Market price at end of period (*$/share*)	**3.25**	2.40
Market value of shares(1)	**305,312**	224,623
Enterprise value(1)	**463,388**	367,766
Net debt as a percentage of enterprise value(1)	**34%**	39%
Trailing twelve months adjusted funds flow(1)	**137,440**	142,073
Net debt to trailing twelve months adjusted funds flow ratio(1)	**1.2**	1.0
Annualized adjusted funds flow(1)(2)	**140,981**	132,660
Net debt to annualized adjusted funds flow ratio(1)(2)	**1.1**	1.1

(1) Non-GAAP measure or ratio. See "Non-GAAP and Other Financial Measures".
(2) Based on Q2 2026 adjusted funds flow, before transaction costs, of $35.2 million (Q4 2025 - $33.2 million). See "Non-GAAP and Other Financial Measures" for more details.

At June 30, 2026, Rubellite had net debt of $158.1 million, a 10% increase from $143.1 million at December 31, 2025. During the first half of 2026, Rubellite's capital expenditures, including land and other spending, of $76.5 million exceeded adjusted funds flow of $68.6 million. Net debt also increased due to payments for other obligations, including a $3.8 million reduction of the other provision, $0.5 million of decommissioning expenditures, $0.8 million of cash-settled share based compensation payments and $0.8 million of cash consideration for the asset swap transaction completed at the end of the second quarter.

Rubellite had available liquidity at June 30, 2026 of $62.9 million, comprised of the $160.0 million credit facility borrowing limit, less $95.7 million of bank borrowings and $1.4 million of outstanding letters of credit.

Bank debt

During the period ended June 30, 2026, the Company's first lien credit facility had its borrowing limit increased to $160.0 million (December 31, 2025 - $140.0 million) and was extended with an initial term to May 31, 2027. The initial term may be extended for a further twelve months to May 31, 2028 subject to lender approval. If not extended by May 31, 2027, all outstanding advances would be repayable on May 31, 2028. The next semi-annual borrowing base redetermination is scheduled on or before November 30, 2026.

As at June 30, 2026, $95.7 million was drawn against the credit facility (December 31, 2025 - $92.6 million) and $1.4 million (December 31, 2025 - $1.4 million) of letters of credit were 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 June 30, 2026 was 5.9% per annum. For the period ended June 30, 2026, if interest rates changed by 1% with all other variables held constant, the impact on cash finance expense and net income (loss) and comprehensive income (loss) 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 June 30, 2026, the credit facility was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Term Loan

			June 30, 2026		December 31, 2025	
(*$ thousands*)	**Maturity date**	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
Term loan	August 2, 2029	11.5%	**20,000**	**19,266**	20,000	19,173

Rubellite has a $20.0 million senior secured third-lien term loan placed, directly or indirectly, with certain directors, officers and employees, and their affiliates, of Rubellite and the Company's significant shareholder. 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.

During the three and six months ended June 30, 2026, Rubellite paid $0.6 million and $1.1 million in cash interest payments to the holders of the term loan (Q2 2025 - $0.6 million; 2025 - $1.1 million).

At June 30, 2026, the term loan was recorded at the present value of future cash flows, net of $0.7 million (December 31, 2025 - $0.8 million) in issue and discount costs which are amortized over the remaining term using a weighted average effective interest rate of 13.0% (December 31, 2025 - 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 June 30, 2026 and December 31, 2025, entities controlled or directed by the Company's Chief Executive Officer ("CEO") hold $18.4 million of the outstanding term loan.

Equity

At June 30, 2026, there were 93.9 million common shares outstanding, net of 0.1 million shares held in trust for employee compensation programs (December 31, 2025 - 93.6 million common shares outstanding, net of 0.1 million of shares held in trust).

At August 7, 2026, there were 93.9 million common shares outstanding, net of 0.1 million shares held in trust for employee compensation programs.

The following table summarizes information about options, rights and awards outstanding as of the date of this MD&A. It includes awards under the Rubellite Incentive Plan and under plans acquired through a business combination (the "Acquired Plans") with Perpetual Energy Inc. ("Perpetual") in the fourth quarter of 2024 (the "Recombination Transaction"):

(thousands)	**August 7, 2026**
Restricted share units	3,323
Share options	2,786
Performance share units	2,454
Perpetual awards(1)	1,652
Total	**10,215**

(1) Of the 1.7 million share based awards under the Acquired Plans outstanding, 1.0 million awards may be settled for cash or from shares in the employee trust as opposed to treasury issuance.

Commodity price risk management

As at August 7, 2026, Rubellite had the following oil commodity risk management contracts:

Commodity	**Volumes Sold (bbl/d)**	**Term**	**Reference/Index**	**Contract Traded Bought/Sold**	**Average Price ($/bbl)**
Crude Oil	4,800 bbl/d	Jul 2026	WTI (US$/bbl)	Swap - sold	$66.19
Crude Oil	5,100 bbl/d	Aug 2026 - Sep 2026	WTI (US$/bbl)	Swap - sold	$67.00
Crude Oil	5,400 bbl/d	Oct 2026 - Dec 2026	WTI (US$/bbl)	Swap - sold	$68.98
Crude Oil	4,350 bbl/d	Jan 2027 - Dec 2027	WTI (US$/bbl)	Swap - sold	$71.31
Crude Oil	1,700 bbl/d	Jan 2028 - Dec 2028	WTI (US$/bbl)	Swap - sold	$70.03
Crude Oil	4,800 bbl/d	Jul 2026 - Sep 2026	WCS Differential (US$/bbl)	Swap - sold	($12.41)
Crude Oil	3,000 bbl/d	Oct 2026 - Dec 2026	WCS Differential (US$/bbl)	Swap - sold	($13.18)

Foreign exchange risk management

As at August 7, 2026, Rubellite had the following foreign exchange risk management contracts:

Fixed Contract	**Notional amount**	**Term**	**Price (CAD$/US$)**
Average rate forward (CAD$/US$)	$2,500,000 US$/month	Jul - Dec 2026	1.4066
Average rate forward (CAD$/US$)(1)	$5,000,000 US$/month	Jul - Dec 2026	1.3890
Average rate forward (CAD$/US$)	$500,000 US$/month	Jul - Dec 2026	1.4086
Average rate forward (CAD$/US$)	$500,000 US$/month	Oct - Dec 2026	1.4100
Average rate forward (CAD$/US$)	$3,000,000 US$/month	Jan -Dec 2027	1.3700
Average rate forward (CAD$/US$)	$2,000,000 US$/month	Jan -Dec 2028	1.3700

(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	**Notional amount**	**Term**	**Floor Price (CAD$/US$)**	**Ceiling Price (CAD$/US$)**	**Reset Price (CAD$/US$)**
Knock-in Collar (CAD$/US$)(1)	$3,000,000 US$/month	Jan - Dec 2027	1.4000	1.4400	1.4200

(1) On September 1, 2027, if the spot price has not traded at or below $1.3810 at any time for the duration of the contract, Rubellite knocks into a US$3.0 million per month contract at a forward rate of 1.4000 CAD$/US$ for the 2028 calendar year.

COMMITMENTS AND CONTRACTUAL OBLIGATIONS

The Company has a drilling commitment on certain GORR lands that must be fulfilled by December 31, 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 June 30, 2026, the Company spud 48 (48.0 net) of the 59 (59.0 net) wells that are required to meet the drilling commitment. Subsequent to June 30, 2026, the Company spud an additional 4 (4.0 net) wells bringing the total to 52 (52.0 net) of the 59 (59 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)	**June 30, 2026**	December 31, 2025
Decommissioning obligations – current	**1,340**	1,340
Decommissioning obligations – non-current	**36,300**	34,302
Total decommissioning obligations	**37,640**	35,642

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

(*$ thousands, except as noted*)	**June 30, 2026**	December 31, 2025
Undiscounted obligations	**50,342**	49,432
Average risk-free rate	**3.8%**	3.9%
Inflation rate	**2.1%**	2.0%
Expected timing of settling obligations	**1 to 25 years**	1 to 25 years

Other provision

($ thousands)	**June 30, 2026**	December 31, 2025
Other provision – current	**3,750**	3,750
Other provision – non-current	**8,150**	11,554
Total other provision(1)(2)	**11,900**	15,304

(1) The other provision was assumed through the Recombination Transaction and relates to a settlement agreement 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.
(2) The other provision is a second-lien obligation of the Company.

The following assumptions were used to estimate the other provision:

(*$ thousands, except as noted*)	**June 30, 2026**	December 31, 2025
Undiscounted obligations	**12,441**	16,191
Average risk-free rate	**3.0%**	3.0%
Expected timing of settling obligations	**3.8 years**	4.3 years

The Company is required to make annual payments of $3.75 million until the principal of the other provision is fully repaid. Annual scheduled payments were made on March 28, 2026 and March 28, 2025. As of March 28, 2026, interest accrues on the outstanding principal and is payable annually at an interest rate equal to the applicable Bank of Canada prime rate on the date of payment, with the remainder of the annual payment applied to the outstanding principal. The Company is able to pre-pay all, or any portion, of the outstanding principal at any time without bonus or penalty.

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. Total capital expenditures includes exploration and development, land, geological and geophysical and corporate spending.

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 June 30,		Six months ended June 30,	
($ thousands)	**2026**	2025	**2026**	2025
Net cash flows used in investing activities	**(30,250)**	(38,630)	**(69,447)**	(63,013)
Payment for asset swap	**(800)**	—	**(800)**	—
Change in non-cash working capital	**14,433**	(7,462)	**7,900**	(6,913)
Total capital expenditures	**(43,883)**	(31,168)	**(76,547)**	(56,100)
Property, plant and equipment additions	**(40,754)**	(27,695)	**(69,354)**	(49,553)
Exploration and evaluation additions	**(2,936)**	(3,417)	**(6,907)**	(6,350)
Corporate expenditures	**(193)**	(56)	**(286)**	(197)
Total capital expenditures	**(43,883)**	(31,168)	**(76,547)**	(56,100)
Add back:				
Corporate and other	**193**	56	**286**	197
Geological and geophysical	**235**	542	**603**	947
Land	**2,461**	6,773	**3,319**	8,876
Exploration and development spending[1]	**(40,994)**	(23,797)	**(72,339)**	(46,080)

(1) Non-GAAP supplementary measure. See "Supplementary Measures".

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 June 30,	
($ thousands, except per boe amounts)	***$/boe***	**2026**	*$/boe*	2025
Net operating costs	**8.16**	**9,949**	6.71	7,591
Transportation	**5.58**	**6,802**	5.93	6,707
General and administrative	**3.24**	**3,948**	3.55	4,015
Cash finance expense	**2.31**	**2,824**	2.07	2,339
Cash costs	**19.29**	**23,523**	18.26	20,652

			Six months ended June 30,	
($ thousands, except per boe amounts)	***$/boe***	**2026**	*$/boe*	2025
Net operating costs	**7.01**	**17,284**	6.85	15,387
Transportation	**5.04**	**12,432**	5.76	12,938
General and administrative	**3.36**	**8,281**	3.75	8,429
Cash finance expense	**1.99**	**4,912**	2.14	4,798
Cash costs	**17.40**	**42,909**	18.50	41,552

Operating netbacks and total operating netbacks, after risk management contracts: Operating netback is calculated by deducting royalties, net operating costs, 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 total operating netback, after risk management contracts to be key industry performance indicators that provide 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 total operating netback, after risk management contracts, are used to evaluate operational performance as they demonstrate profitability relative to realized and current commodity prices.

Net operating costs: Net operating costs equals operating expenses net of processing 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 June 30,		Six months ended June 30,	
(*$ thousands, except per boe amounts*)	**2026**	2025	**2026**	2025
Other income	**194**	403	**327**	505
Less: Non processing income	**—**	(343)	**—**	(343)
Processing income	**194**	60	**327**	162
Production and operating	**10,143**	7,651	**17,611**	15,549
Less: processing income	**(194)**	(60)	**(327)**	(162)
Net operating costs	**9,949**	7,591	**17,284**	15,387
$/boe	**8.16**	6.71	**7.01**	6.85

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 June 30, 2026**	As of December 31, 2025
Current assets	**38,984**	35,181
Current liabilities	**(89,837)**	(70,413)
Working capital deficit	**50,853**	35,232
Risk management contracts – current asset	**6,367**	5,828
Risk management contracts – current liability	**(2,829)**	(327)
Lease liability - current liability	**(359)**	(389)
Share based compensation liability - current liability	**(6,526)**	(4,694)
Decommissioning obligations – current liability	**(1,340)**	(1,340)
Other provision - current liability	**(3,750)**	(3,750)
Adjusted working capital deficit(1)	**42,416**	30,560
Bank indebtedness	**95,660**	92,583
Term loan (principal)	**20,000**	20,000
Net debt(2)	**158,076**	143,143

(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 cash-settled 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 June 30,		Six months ended June 30,	
(*$ thousands, except as noted*)	**2026**	2025	**2026**	2025
Net cash flows from operating activities	**42,770**	35,808	**67,349**	62,943
Change in non-cash working capital	**(7,701)**	495	**(3,835)**	4,575
Cash-settled share based compensation	**71**	889	**800**	1,085
Other provision settled	**—**	—	**3,750**	3,750
Decommissioning obligations settled	**105**	119	**548**	892
Adjusted funds flow	**35,245**	37,311	**68,612**	73,245
Adjusted funds flow per share - basic	**0.38**	0.40	**0.73**	0.79
Adjusted funds flow per share - diluted	**0.36**	0.39	**0.70**	0.77
Adjusted funds flow per boe	**28.88**	32.80	**27.83**	32.58

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, excluding non-cash items and acquisitions and dispositions. Adjusted funds flow and capital expenditures are non-GAAP financial measures which have been reconciled to their most directly comparable GAAP measures previously in this document. By comparing current period capital expenditures relative to adjusted funds flow, Rubellite monitors its free funds flow to inform decisions such as capital allocation, debt repayment and liquidity.

The following table shows the calculation of the removal of capital expenditures from adjusted funds flow:

	Three months ended June 30,		Six months ended June 30,	
(*$ thousands*)	**2026**	2025	**2026**	2025
Adjusted funds flow	**35,245**	37,311	**68,612**	73,245
Total capital expenditures	**(43,883)**	(31,168)	**(76,547)**	(56,100)
Free funds flow	**(8,638)**	6,143	**(7,935)**	17,145

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 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: 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: calculated on a trailing twelve-month basis.

Net debt to annualized adjusted funds flow ratio: calculated by annualizing the current quarter adjusted funds flow.

Net debt as a percentage of enterprise value: calculated by dividing net debt by enterprise value at the end of the period.

Adjusted funds flow per share: calculated on a per share basis as the measure divided by common shares outstanding at the end of the period.

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

Supplementary Financial Measures

"Exploration and development spending" is comprised of the non-GAAP measure total capital expenditures (as calculated above), less land, geological and geophysical and corporate and other spending.

"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 boe 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 bbl" 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 total oil and natural gas revenue, 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 cost per boe" is comprised of net operating cost (as calculated above), divided by the Company's total sales production.

"Transportation cost ($/boe)" is comprised of transportation, 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 and depreciation 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 at period end.

“Heavy oil wellhead differential ($/bbl)” represents the differential the Company receives for selling its heavy oil production relative to the Western Canadian Select reference price (CAD$/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 April 1, 2026 and ending June 30, 2026 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, and the benefits to be derived from such drilling including drilling techniques, pilot projects and production growth including the timing for and benefits of EOR initiatives; the plan to advance strategic initiatives including multiple enhanced oil recovery pilots, exploration activities, new land capture, capital spending activities in the Company's core properties at Figure Lake and Frog Lake, anticipated average heavy oil sales volumes and total production sales volumes in 2026; the expectation that capital spending activity will be funded from adjusted funds flow, with excess free funds flow to reduce net debt and for other balance sheet obligations; operating and transportation cost forecasts for 2026; planned ARO spending; the anticipated number of drilling rigs to operate for the remainder of 2026; Rubellite's business plan; and including the forward-looking information contained under the headings "Operations Update" and "About Rubellite".

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, South America and elsewhere), 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, 2025 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
Mboe	thousand 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.

References to natural gas, crude oil and condensate and NGL production in the MD&A refer to conventional natural gas, heavy crude oil and natural gas liquids, respectively, product types as defined in National Instrument 51-101.

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.

Financial and Business Environment:

AECO	Alberta Energy Company
E&E	Exploration and evaluation
EOR	Enhanced oil recovery
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
OBM	Oil based mud
PP&E	Property, plant and equipment
WTI	West Texas Intermediate
WCS	Western Canadian Select

SUMMARY OF QUARTERLY RESULTS

($ thousands, except as noted)	**Q2 2026**	**Q1 2026**	**Q4 2025**	**Q3 2025**
Financial				
Oil and natural gas revenue	**86,063**	66,243	56,261	58,290
Net income (loss) and comprehensive income (loss)	**34,119**	(23,071)	9,700	5,646
Per share – basic(2)	**0.36**	(0.25)	0.10	0.06
Per share – diluted(2)	**0.35**	(0.25)	0.10	0.06
Total assets	**615,606**	597,152	578,509	558,709
Cash flow from operating activities	**42,770**	24,579	30,900	34,953
Adjusted funds flow(1)	**35,245**	33,367	33,165	35,663
Per share – basic(1)(2)	**0.38**	0.36	0.35	0.38
Per share – diluted(1)(2)	**0.36**	0.36	0.34	0.37
Total capital expenditures(1)(5)	**43,883**	32,664	39,037	35,365
Common shares (thousands)				
Weighted average – basic	**93,859**	93,590	94,488	93,700
Weighted average – diluted	**98,313**	93,590	97,478	96,311
Sales Production				
Heavy oil (bbl/d)	**8,534**	8,641	8,295	8,338
Natural gas (Mcf/d)	**26,576**	28,532	25,884	20,975
NGL (bbl/d)	**443**	447	433	288
Daily average sales production (boe/d)	**13,406**	13,843	13,042	12,122
Rubellite average realized price(1)				
Oil ($/bbl)	**101.17**	74.42	63.32	72.40
Natural gas ($/Mcf)	**1.73**	2.27	2.47	0.66
NGL ($/bbl)	**81.97**	63.10	51.93	56.12
Total average realized price ($/boe)	**70.54**	53.17	46.89	52.27
Average realized price, after risk management contracts(2) ($/boe)	**58.70**	49.37	49.20	55.83
Operating netback ($/boe)				
Revenue(2)	**70.54**	53.17	46.89	52.27
Royalties(2)	**(10.53)**	(7.02)	(6.14)	(7.18)
Net operating costs(2)	**(8.16)**	(5.89)	(5.80)	(6.46)
Transportation costs(2)	**(5.58)**	(4.52)	(4.57)	(4.66)
Operating netback(2)	**46.27**	35.74	30.38	33.97
Realized gain (loss) on risk management contracts(2)	**(11.84)**	(3.80)	2.31	3.56
Total operating netback, after risk management contracts(2)	**34.43**	31.94	32.69	37.53
G&A Costs(2)	**(3.24)**	(3.48)	(3.19)	(3.24)
Cash interest costs(2)	**(2.31)**	(1.68)	(1.85)	(2.30)
Adjusted funds flow(2)	**28.88**	26.78	27.65	31.99

(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) In Q3 2025 and Q4 2025, the Company disposed of non-producing acreage for cash consideration of $5.5 million and $2.3 million respectively, with a net book value of nil, resulting in a corresponding gain on disposition of assets.

($ thousands, except as noted)	Q2 2025	Q1 2025	Q4 2024	Q3 2024
Financial				
Oil and natural gas revenue	60,542	66,607	59,081	43,682
Net income and comprehensive income	16,051	1,160	26,747	15,010
Per share – basic[2]	0.17	0.01	0.31	0.23
Per share – diluted[2]	0.17	0.01	0.30	0.23
Total assets	561,545	551,889	562,612	432,836
Cash flow from operating activities	35,808	27,135	39,402	19,973
Adjusted funds flow, after transaction costs[1][4]	37,311	35,934	31,632	23,029
Per share – basic[1][2]	0.40	0.39	0.36	0.35
Per share – diluted[1][2]	0.39	0.38	0.36	0.35
Total capital expenditures[1]	31,168	24,932	35,537	36,650
Acquisitions[3]	—	—	68,467	62,732
Common shares (thousands)				
Weighted average – basic	93,279	92,930	87,655	65,834
Weighted average – diluted	95,074	95,068	88,546	66,571
Sales Production				
Heavy oil (bbl/d)	8,637	8,339	7,754	5,954
Natural gas (Mcf/d)	20,522	22,038	14,140	—
NGL (bbl/d)	368	371	275	—
Daily average sales production (boe/d)	12,425	12,383	10,386	5,954
Rubellite average realized price[1]				
Oil ($/bbl)	69.98	80.03	76.97	79.75
Natural gas ($/Mcf)	1.93	2.16	2.01	—
NGL ($/bbl)	57.92	67.54	61.32	—
Total average realized price ($/boe)	53.54	59.77	61.83	79.75
Average realized price, after risk management contracts[2] ($/boe)	57.81	59.60	65.14	80.06
Operating netback ($/boe)				
Revenue[2]	53.54	59.77	61.83	79.75
Royalties[2]	(6.75)	(8.48)	(8.10)	(9.60)
Net operating costs[2]	(6.71)	(7.00)	(6.84)	(8.46)
Transportation costs[2]	(5.93)	(5.59)	(6.01)	(7.67)
Operating netback[2]	34.15	38.70	40.88	54.02
Realized gain (loss) on risk management contracts[2]	4.27	(0.17)	3.31	0.31
Total operating netback, after risk management contracts[2]	38.42	38.53	44.19	54.33
G&A Costs[2]	(3.55)	(3.96)	(3.69)	(4.87)
Cash interest costs[2]	(2.07)	(2.21)	(2.98)	(4.42)
Adjusted funds flow, before transaction costs[2]	32.80	32.36	37.52	45.04

(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) Q4 2024 and Q3 2024 include $4.2 million and $2.0 million, respectively, of transaction costs related to prior period transactions.

Oil and natural gas revenue has ranged between $43.7 million and $86.1 million over the prior eight quarters largely due to increasing sales volumes from 5,954 boe/d to over 13,000 boe/d, partially offset by volatility in commodity pricing. Net income (loss) has ranged between a loss of $23.1 million and income of $34.1 million primarily due to increased production, corporate acquisitions and dispositions, volatility of commodity prices and its impact on revenue, royalties, realized and unrealized risk management contract gains and losses and deferred income taxes.