

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 months ended March 31, 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 consolidated interim financial statements and accompanying notes for the three months ended March 31, 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 May 8, 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".

FIRST QUARTER 2026 OPERATIONAL AND FINANCIAL HIGHLIGHTS

Operational Highlights

- **Heavy oil sales production:** Averaged a record 8,641 bbl/d in the first quarter of 2026, an increase of 4% from 8,339 bbl/d in the first quarter of 2025 and a 4% increase from 8,295 bbl/d in the fourth quarter of 2025, exceeding first quarter guidance of 8,300 to 8,400 bbl/d.
- **Total sales production:** Averaged a record 13,843 boe/d in the first quarter of 2026 (66% heavy oil and natural gas liquids ("NGL")), an increase of 12% from 12,383 boe/d (70% heavy oil and NGL) in the first quarter of 2025 and a 6% increase from 13,042 boe/d in Q4 2025, exceeding first quarter guidance of 13,300 to 13,400 boe/d.
- **Heavy oil activity:** Brought 10 (9.5 net) heavy oil wells on production at Figure Lake and Frog Lake during the first quarter.
- **West Central natural gas activity:** Added 2 (1.0 net) liquids-rich conventional natural gas wells to production at East Edson at the end of the fourth quarter of 2025 and 2 (1.0 net) additional wells during the first quarter.
- **Exploration and development spending⁽¹⁾:** Spent \$31.3 million in the first quarter, within the guided range of \$30.0 to \$32.0 million. First quarter spending included the drilling and completion of 4 (4.0 net) multi-lateral horizontal Clearwater development wells, and 1 (1.0 net) waterflood pilot producer-injector pair at Figure Lake (2.0 net drills); 3 (2.5 net) multi-lateral horizontal Waseca development wells at Frog Lake; 1 (1.0 net) exploration well on a new prospect in Saskatchewan; and the drilling, completion, equipping and tie-in of 2 (1.0 net) liquids-rich conventional natural gas wells at East Edson that commenced drilling late in 2025.
- **Land and geological and geophysical spending:** Spent \$0.9 million on land to capture acreage in core areas and for exploration prospects, and \$0.4 million on geological and geophysical activities related to completion of the 3D seismic program at Frog Lake, which commenced in the fourth quarter of 2025.
- **Abandonment and reclamation:** Spent \$0.4 million on decommissioning, abandonment and reclamation activities and received one reclamation certificate from the Alberta Energy Regulator ("AER") (Q1 2025 - one).

Financial Highlights

- **Adjusted funds flow⁽¹⁾:** \$33.4 million (\$0.36 per share) in the first quarter of 2026, a decrease of 7% from \$35.9 million (\$0.39 per share) in the first quarter of 2025.
- **Cash costs⁽¹⁾:** \$19.4 million or \$15.57/boe in the first quarter of 2026, representing a 17% decrease on a per boe basis as compared to the first quarter of 2025 (Q1 2025 - \$20.9 million or \$18.76/boe).
- **Net loss:** \$23.1 million (\$0.25 per share) in the first quarter of 2026 (Q1 2025 - \$1.2 million net income or \$0.01 per share) primarily driven by an unrealized loss on risk management contracts.
- **Net debt⁽¹⁾:** \$148.0 million at March 31, 2026, an increase of 3% from \$143.1 million at December 31, 2025. Positive free funds flow⁽¹⁾ of \$0.7 million generated during the first quarter was primarily used to reduce other obligations, including a \$3.8 million reduction of the other provision, \$0.4 million of decommissioning expenditures and \$0.7 million of cash-settled share based compensation payments.
- **Available liquidity⁽²⁾:** \$30.8 million at March 31, 2026, based on a \$140.0 million first-lien credit facility borrowing limit, less \$107.8 million of bank borrowings and \$1.4 million in letters of credit. Subsequent to the end of the quarter, the borrowing limit was increased to \$160.0 million, further enhancing available liquidity.

(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".

Q1 2026 GUIDANCE RECONCILIATION

During the first quarter of 2026, Rubellite recorded strong growth from a successful drilling program, which saw both heavy oil and total sales production exceed the high end of the Q1 2026 guidance range. Rubellite's heavy oil wellhead differential of \$4.81/bbl in Q1/26 exceeded the guided range \$3.50 to \$4.00/bbl due to higher than expected diluent costs. A comparison of the Company's most recent Q1 2026 guidance metrics to actual results is provided below.

	Q1 2026 Guidance ⁽¹⁾	Q1 2026 Actuals
Sales Production (boe/d)	13,300 - 13,400	13,843
Production mix (% oil and NGL)	67%	66%
Heavy oil sales production (bbl/d)	8,300 - 8,400	8,641
Exploration and development spending (\$ millions) ⁽²⁾⁽³⁾	\$30 - \$32	\$31.3
Heavy oil wellhead differential (\$/bbl) ⁽²⁾	\$3.50 - \$4.00	\$4.81
Royalties (% of revenue) ⁽²⁾	13% - 14%	13%
Production and operating costs (\$/boe) ⁽²⁾	\$6.50 - \$7.25	\$5.89
Transportation costs (\$/boe) ⁽²⁾	\$4.50 - \$5.00	\$4.52
General and administrative costs (\$/boe) ⁽²⁾	\$3.00 - \$3.50	\$3.48

(1) Q1 2026 guidance dated March 10, 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 first quarter, Rubellite drilled and rig released 4 (4.0 net) Clearwater primary development multi-lateral horizontal wells targeting the Wabiskaw Member of the Clearwater Formation, using the optimized 33 meter inter-leg spacing and 15,000 meters open hole length at the 8-26-61-16W4 Surface Pad (the "8-26 Pad"). Initial well performance continues to exceed expectations, with average⁽¹⁾ IP30/60 rates of 303 bbl/d (3 wells)/300 bbl/d (2 wells), compared to the 2025 McDaniel Tier 1 type curve⁽²⁾ of IP30/60 of 201/193 bbl/d⁽²⁾.

Drilling operations continued at the 8-26 Pad into the second quarter. In early April, a second drilling rig was added to supplement the one-rig program and is expected to drill a minimum of 8.0 and up to 13.0 net additional Clearwater multi-lateral horizontal wells to grow heavy oil production in this stronger commodity price environment. Continuation of the second rig into the fourth quarter is contingent upon future heavy oil prices.

A well targeting the Sparky Formation (1.0 net) drilled in the fourth quarter of 2025 continues to deliver encouraging results, with an IP30/60 rate of 286 bbl/d/259 bb/d and water cut averaging 10%. The well has 6 legs and approximately 7,750 meters of horizontal length. Continuous production from the initial well and further development of the Sparky discovery pool will require construction of a permanent all season access road and pad expansion, which are currently planned for the second half of 2026. The well was temporarily shut in during spring breakup and will be restarted later in the second quarter following completion of interim access upgrades. Two (2.0 net) additional Sparky wells are planned for the fourth quarter of 2026.

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").

A second waterflood pilot at Figure Lake was advanced in the first quarter of 2026, with the drilling of an 8-leg horizontal multi-lateral producer (1.0 net) on the 8-26 Pad, straddling a dedicated single-leg injection well (1.0 net). The 4-leg sets on each side of the injector were drilled with 25 meter inter-leg spacing, and offset from the injector by 75 meters. Total open hole length for the 8 legs is approximately 9,900 meters. Initial well performance for the 8 leg producer exceeded expectations with an average IP30 rate of 283 bbl/d. Water injection for this pilot is expected to commence late in the second quarter.

Subsequent to the end of the quarter, a third dedicated producer (1.0 net) and injector (1.0 net) pair were drilled on the 08-26 Pad to evaluate the utility and effectiveness of polymer injection on oil recovery. The 8 leg producer recovered oil based mud ("OBM") on April 20th and achieved an IP(15) of 185 bbl/d. Polymer injection is expected to commence in the fourth quarter.

In addition, two multi-lateral horizontal producer-to-injector conversions on two separate pads at Figure Lake were advanced, with water injection initiated on the 1-3 Pad in March 2026, and water injection expected to be initiated on the 1-13 Pad in the second quarter. These producer-to-injector conversion pilots will evaluate the effectiveness of waterflood where primary production has already occurred through multi-lateral drilling development.

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

Frog Lake

Waseca Update - Open Hole Horizontal Multi-laterals:

During the first quarter, Rubellite drilled and rig released 3 (2.5 net) open hole multi-lateral wells targeting the Waseca Formation.

- Waseca North: 2 (2.0 net) wells achieved average⁽¹⁾ IP30/IP60 rates of 130 bbl/d (2 wells)/134 bbl/d (1 well), exceeding the 2025 McDaniel type curve⁽²⁾ of 122/117 bbl/d.
- Waseca South: 1 (0.5 net) well achieved an average IP30/IP60 rate of 68 bbl/d, below the 2025 McDaniel type curve⁽²⁾ of 145 bbl/d due to a combination of thinning reservoir and higher shale content encountered at the toe of the well.

Rubellite suspended drilling operations at Frog Lake on February 5, 2026 to allow the drilling rig, which operated continuously for several years, to undergo servicing and recertification. Drilling recommenced at Frog Lake on April 19, 2026, with the spud of an extended reach

Waseca North well (1.0 net). The well is targeting up to 20,000m of open hole, as compared to historical 15,000m of open hole, and using a new water-based amine mud system to reduce costs, improve hole cleaning, and limit fluid losses to the formation while drilling.

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. Four (3.0 net) GP wells have been drilled to date using both single-leg and fishbone designs, of which three were completed with recycle strings. Early IP30⁽¹⁾ performance across the three wells completed with recycle strings ranged from 44–134 bbl/d, with an average of 78 bbl/d. The most recent of those three wells, 00/09-23-056-03W4 (50% working interest), has been on production since December 19, 2025, and following startup and tubing string optimization, is currently producing at an average of 145 bbl/d gross. For reference, the McDaniel year-end 2025 type curve⁽²⁾ for the GP formation assumes an IP30/IP60 of 73/72 bbl/d.

Other Operational Updates:

Approximately 26 km² of new 3D seismic was acquired in late 2025 and early 2026 to support future drilling plans at Frog Lake.

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

East Edson

Two (1.0 net) Wilrich development wells were rig released, fracture stimulated, equipped, and tied-in following drilling that commenced in late 2025, with both wells brought on production in February.

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 multiple 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 until spring breakup, at which time the well was temporarily shut in. An extended production evaluation period is planned once road restrictions are lifted.

- (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 conventional 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 \$135 million, with the range reflecting the expected duration of a second drilling rig at Figure Lake. In addition to development drilling in its core heavy oil operating areas, 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 mid-2026; (2) initiating polymer injection on the producer-injector pair drilled for a polymer flood pilot, with injection planned to commence in Q4 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.

Capital Program - Q1 2026:

Figure Lake:

- Drilled and completed 4 (4.0 net) 15,000m, 12 leg, Clearwater primary development wells; and
- Drilled and completed 1 (1.0 net) 10,000m, 8 leg, waterflood pilot producer and 1.0 (1.0 net) injector on the 8-26 Pad.

Frog Lake:

- Drilled and completed 1 (0.5 net) Waseca South development wells; and
- Drilled and completed 2 (2.0 net) Waseca North development wells.

East Edson:

- Drilled, fracture stimulated, equipped, and tied-in 2 (1.0 net) Wilrich natural gas development wells.

Exploration:

- Drilled and completed 1 (1.0 net) exploration well at Bayhurst, Saskatchewan.

Capital Program - Remainder of 2026:

At Figure Lake:

- Drilling and completion of 17 (17.0 net) to 22 (22.0 net) 15,000m, 12 leg, Clearwater primary development wells;
- Drilling and completion of 2 (2.0 net) 10,000m, 10 leg, Clearwater step-out wells;
- Drilling and completion of 2 (2.0 net) 10-15,000m, 12 leg, Sparky wells;
- Drilling and completion of 1 (1.0 net) 10,000m, 8 leg, polymer flood pilot producer and 1 (1.0 net) injector on the '8-26 Pad';
- Surface and downhole equipping activities related to two mature multi-lateral producer to waterflood injector conversions; and
- Additional core testing to continue informing EOR initiatives.

At Ukalta:

- Conversion of an existing mature multi-lateral producer to waterflood injector, with water injection expected to commence in the second quarter.

At Frog Lake:

- Drilling and completion of 24 (13.0 net) wells targeting the Waseca North, Waseca South, GP and Sparky zones;
- Drilling and completion of 1 (0.5 net) water disposal well; and
- 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 8,800 to 9,200 bbl/d, while total production sales volumes, including natural gas and NGL volumes, are forecast to average 13,300 to 13,800 boe/d, representing 7% to 10% growth relative to 2025.

Building on continued efficiency gains, operating costs are forecast to average \$6.50 to \$7.00/boe for 2026, and transportation costs are forecast to average \$4.75 to \$5.25/boe, reflecting anticipated increased fuel surcharges for trucked oil. Heavy oil wellhead differentials are forecast to average \$4.50 to \$5.50/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 \$1.4 million of abandonment and reclamation expenditures planned for the remainder of 2026, satisfying the Company's AER area-based mandatory 2026 spending requirement of \$1.4 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:

	Q1 2026		Q2 - Q4 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⁾		6 / 6.0		23 - 28 / 23.0 - 28.0		29 - 34 / 29.0 - 34.0
Frog Lake		3 / 2.5		25 / 13.5		28 / 16.0
Marten Hills		- / -		- / -		- / -
East Edson		2 / 1.0		- / -		2 / 1.0
Other Exploration		1 / 1.0		- / -		1 / 1.0
Total	\$31.3	12 / 10.5	\$94 - \$104	48 - 53 / 36.5 - 41.5	\$125 - \$135	60 - 65 / 47.0 - 52.0

(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 will be the polymer pilot producer-injector pair on the 8-26 Pad at Figure Lake.

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

	Q2 2026 Guidance	Full Year 2026 Guidance
Sales production (boe/d)	13,300 - 13,400	13,300 - 13,800
Production mix (% oil and NGL)	68%	69%
Heavy oil sales production (bbl/d)	8,550 - 8,650	8,800 - 9,200
Exploration and development spending (\$ millions) ⁽¹⁾⁽²⁾	\$39 - \$41	\$125 - \$135
Heavy oil wellhead differential (\$/bbl) ⁽¹⁾	\$5.50 - \$6.00	\$4.50 - \$5.50
Royalties (% of revenue) ⁽¹⁾	15.5% - 16.5%	14.5% - 15.5%
Production and operating costs (\$/boe) ⁽¹⁾	\$6.50 - \$7.25	\$6.50 - \$7.00
Transportation costs (\$/boe) ⁽¹⁾	\$4.75 - \$5.25	\$4.75 - \$5.25
General and administrative costs (\$/boe) ⁽¹⁾	\$3.00 - \$3.50	\$3.00 - \$3.50

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

(2) Excludes abandonment and reclamation spending, land and geological expenditures, if any.

FIRST 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, 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:

(\$ thousands)	2026			2025		
	E&E	PP&E	Total	E&E	PP&E	Total
Drilling and completions	2,638	20,709	23,347	1,032	17,939	18,971
Facilities	433	7,546	7,979	228	3,085	3,313
Exploration and development spending ⁽¹⁾	3,071	28,255	31,326	1,260	21,024	22,284
Land	780	95	875	1,268	834	2,102
Geological and geophysical ("G&G")	120	250	370	405	—	405
Corporate and other	—	93	93	—	141	141
Total capital expenditures ⁽¹⁾	3,971	28,693	32,664	2,933	21,999	24,932

(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")

(\$ thousands)	Three months ended March 31,	
	2026	2025
Eastern Heavy Oil	26,148	21,703
West Central	5,178	581
Exploration and development spending ⁽¹⁾	31,326	22,284

(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

(gross/net)	Three months ended March 31,	
	2026	2025
Development		
Figure Lake ⁽¹⁾⁽²⁾	6 / 6.0	4 / 4.0
Frog Lake ⁽³⁾	3 / 2.5	6 / 4.5
Marten Hills waterflood injection ⁽⁴⁾	- / -	1 / 0.3
Edson ⁽⁵⁾	2 / 1.0	- / -
Exploration		
Other exploratory ⁽⁶⁾	1 / 1.0	1 / 1.0
Total	12 / 10.5	12 / 9.8

(1) 1 (1.0 net) well drilled at Figure Lake was spud on March 27, 2026 and rig released April 7, 2026 and not included in the Q1 2026 well count.

(2) 2 (2.0 net) wells drilled in Q1 2026 at Figure Lake were the waterflood pilot 8-leg producer and single-leg injector pair on the 8-26 pad at Figure Lake.

(3) Two wells drilled in Q1 2026 were at 100% working interest. Frog Lake Energy Resources Corp. ("FLERC") has the option on wells drilled in Frog Lake to elect for a 50% working interest in the well or alternatively earn a gross overriding royalty.

(4) 1 (0.3 net) injection waterflood well was drilled at Marten Hills on the 12-35 Pad during Q1 2025.

(5) 2 (1.0 net) wells drilled at East Edson were spud in December 2025 and rig released in January 2026 and included in the Q1 2026 well count.

(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 first quarter of 2026, the Company spent \$31.3 million on exploration and development spending, before land, geological and geophysical, corporate and other spending (Q1 2025 - \$22.3 million). Capital program activities in the first quarter included the following:

- At Figure Lake, the Company drilled 6 (6.0 net) wells at Figure Lake and completed and brought on production 7 (7.0 net) wells. At Figure Lake 4 (4.0 net) of the wells drilled were multi-lateral horizontal producers on the 8-26 Pad targeting primary development of the Clearwater formation and 2 (2.0 net) of the wells drilled were for a waterflood pilot on the 8-26 Pad, with an 8-leg producer and a single-leg injector. A portion of capital to drill 1 (1.0 net) additional polymer flood pilot 8-leg producer well on the 8-26 Pad was spent during the first quarter and the well was rig released early in the second quarter of 2026, with the single-leg polymer injection well drilled in the second quarter of 2026.
- At Frog Lake, drilled 3 (2.5 net) Waseca development wells.
- The Company drilled 1 (1.0 net) exploration well in Saskatchewan.
- At East Edson, 2 (1.0 net) Wilrich horizontal wells were fracture stimulated, equipped, and tied-in following drilling that commenced in late 2025, with both wells brought on production in February by the Company's 50% joint venture partner.

Land spending totalled \$0.9 million in the first quarter of 2026 to capture acreage in core areas and for exploration prospects (Q1 2025 - \$2.1 million). Geological and geophysical spending totaled \$0.4 million (Q1 2025 - nil) and primarily related to completion of the 3D seismic survey at Frog Lake which commenced in the fourth quarter of 2025.

Rubellite spent \$0.4 million (Q1 2025 - \$0.8 million) on abandonment and reclamation projects and received one reclamation certificate from the AER (Q1 2025 - one certificate).

Sales Production

	Three months ended March 31,	
	2026	2025
Sales volumes		
Heavy oil (bbl/d)	8,641	8,339
Natural gas (Mcf/d)	28,532	22,038
NGL (bbl/d) ⁽²⁾	447	371
Total sales volumes (boe/d)	13,843	12,383

Sales production for the three months ended March 31, 2026 by CGU:

	Three months ended March 31,	
	2026	2025
Sales volumes by CGU		
Eastern Heavy Oil (boe/d)	9,629	8,675
West Central (boe/d)	4,214	3,708
Total sales volumes (boe/d)	13,843	12,383

Total sales production for the three months ended March 31, 2026 increased by 1,460 boe/d, or 12%, driven by the Company's successful drilling program and increased solution gas conservation at the Figure Lake gas plant. Heavy oil sales averaged 8,641 bbl/d in the first quarter of 2026, exceeding guidance of 8,300 to 8,400 bbl/d, while total sales averaged 13,843 boe/d, also exceeding guidance of 13,300 to 13,400 boe/d.

First quarter heavy oil sales production averaged 8,641 bbl/d, an increase of 4% from 8,339 in the first quarter of 2025. During the first quarter of 2026, 10 (9.5 net) heavy oil wells were added to sales, with an additional 2 (2.0 net) wells recovering OBM drilling fluid and not yet contributing to sales.

First quarter natural gas production averaged 28.5 MMcf/d, an increase of 29% from 22.0 MMcf/d in the first quarter of 2025. In the West Central area, 2 (1.0 net) liquids-rich conventional natural gas wells were brought on production at the end of the fourth quarter of 2025, followed by 2 (1.0 net) additional wells drilled during the first quarter of 2026. In addition, the Figure Lake gas plant contributed an average of 5.8 MMcf/d of natural gas sales during the first quarter, compared to 2.0 MMcf/d in the first quarter of 2025.

First quarter NGL production averaged 447 bbl/d, a 20% increase from the first quarter of 2025 and consistent with the increase in natural gas volumes.

Rubellite's sales product mix averaged 66% heavy oil and NGL and 34% natural gas during the first quarter (Q1 2025 - 70% heavy oil and NGL and 30% natural gas), reflecting increased solution gas conservation at Figure Lake and the timing of East Edson drilling activities.

Revenue

(\$ thousands, except as noted)	Three months ended March 31,	
	2026	2025
Oil and natural gas revenue		
Oil	57,875	60,061
Natural gas	5,830	4,290
NGL	2,538	2,256
Oil and natural gas revenue	66,243	66,607
Reference prices		
West Texas Intermediate (WTI) (US\$/bbl)	71.93	71.42
Foreign Exchange rate (CAD\$/US\$)	1.37	1.44
WTI (CAD\$/bbl)	98.54	102.84
Western Canadian Select (WCS) differential (US\$/bbl)	(14.16)	(12.67)
WCS (CAD\$/bbl)	79.23	84.30
Heavy oil wellhead differential (CAD\$/bbl)	4.81	4.27
AECO 5A Daily Index (CAD\$/GJ)	1.73	2.05
AECO 5A Daily Index (CAD\$/Mcf) ⁽¹⁾	1.82	2.16
Rubellite average realized prices ⁽²⁾		
Oil (\$/bbl)	74.42	80.03
Natural gas (\$/Mcf)	2.27	2.16
NGL (\$/bbl)	63.10	67.54
Average realized price (\$/boe)	53.17	59.77

(1) Converted from \$/GJ using a standard energy conversion rate of 1.06 GJ:1 Mcf.

(2) Before risk management contracts; supplementary financial measure. See "Non-GAAP and Other Financial Measures".

Rubellite's oil and natural gas revenue decreased by \$0.4 million, or 1%, in the first quarter of 2026, reflecting lower commodity prices, partially offset by a 12% increase in sales volumes.

Oil revenue for the first quarter of 2026 was \$57.9 million, representing 87% of total revenue, while heavy oil production was 62% of total sales volumes. The 4% decline in oil revenue was driven by a 7% reduction in average realized oil prices, which more than offset a 4% increase in heavy oil sales volumes. The WCS price averaged \$79.23/bbl in the first quarter (Q1 2025 - \$84.30/bbl), reflecting the impact of a stronger Canadian dollar at \$1.37 (CAD\$/US\$ rate of \$1.44 in Q1 2025) and a widening of the WCS differential to US\$14.16/bbl (Q1 2025 - US\$12.67/bbl). Rubellite's realized oil price reflects quality adjustments and optimization of sales delivery points, resulting in a lower price offset that averaged \$4.81/bbl during the first quarter of 2026 (Q1 2025 - \$4.27/bbl), and was outside the guided range of \$3.50 to \$4.00/bbl primarily due to higher than expected diluent costs.

Natural gas revenue in the first quarter of 2026 was \$5.8 million, representing 9% of total revenue, while natural gas production accounted for 34% of total sales volumes. The 36% increase in natural gas revenue was driven by a 29% increase in natural gas sales volumes and higher average realized natural gas prices. Although the average AECO Daily Index price decreased to \$1.82/Mcf in the first quarter of 2026 (Q1 2025 - \$2.16/Mcf), the Company's average realized natural gas price increased by 5%, attributable to price optimization during January and February when sales volumes were higher.

NGL revenue was \$2.5 million in the first quarter of 2026, representing 4% of total revenue and 3% of total sales volumes. The 13% increase in NGL revenue was due to a 20% increase in NGL sales volumes, partially offset by a 7% decrease in average realized NGL prices.

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:

(\$ thousands, except as noted)	Three months ended March 31,	
	2026	2025
Unrealized gain (loss) on risk management contracts		
Unrealized loss on oil contracts ⁽¹⁾	(30,766)	(5,020)
Unrealized gain (loss) on natural gas contracts	804	(2,587)
Unrealized loss on risk management contracts	(29,962)	(7,607)
Realized gain (loss) on risk management contracts		
Realized loss on oil contracts ⁽¹⁾	(5,053)	(2,028)
Realized gain on natural gas contracts	313	1,840
Realized loss on risk management contracts	(4,740)	(188)

(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 March 31,	
	2026	2025
Realized gain (loss) on risk management contracts		
Realized loss on oil contracts (\$/bbl) ⁽¹⁾	(6.50)	(2.70)
Realized gain on natural gas contracts (\$/Mcf)	0.12	0.93
Realized loss on risk management contracts (\$/boe)	(3.80)	(0.17)
Average realized prices after risk management contracts ⁽²⁾		
Oil (\$/bbl)	67.92	77.33
Natural gas (\$/Mcf)	2.39	3.09
NGL (\$/bbl)	63.10	67.54
Average realized price (\$/boe) ⁽²⁾	49.37	59.60

(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 \$4.7 million, or \$3.80/boe, for the first quarter of 2026 (Q1 2025 - realized loss of \$0.2 million, or \$0.17/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 loss on risk management contracts was \$30.0 million in the first quarter of 2026 (Q1 2025 - \$7.6 million unrealized loss). 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 March 31,	
	2026	2025
<i>(\$ thousands, except as noted)</i>		
Royalty expenses	8,750	9,449
<i>\$/boe</i>	7.02	8.48
Royalties (% of revenue) ⁽¹⁾	13.2	14.2

(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, some of which are price sensitive and fluctuate with commodity pricing.

Total royalties were \$8.8 million in the first quarter of 2026, a decrease from \$9.4 million in the first quarter of 2025 reflecting lower commodity prices, partially offset by higher production.

On a per boe basis, royalties averaged \$7.02/boe during the first quarter of 2026 (Q1 2025 - \$8.48/boe), a decrease from the first quarter of 2025 due to higher sales volumes and lower prices.

In the first quarter of 2026, royalties as a percentage of revenue were 13.2%, within the guided range of 13% to 14%.

Net operating costs⁽¹⁾

	Three months ended March 31,	
	2026	2025
<i>(\$ thousands, except as noted)</i>		
Net operating costs ⁽¹⁾	7,335	7,796
<i>\$/boe</i>	5.89	7.00

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

Total net operating costs decreased to \$7.3 million in the first quarter of 2026, compared to \$7.8 million in the first quarter of 2025, reflecting initiatives to continue to reduce field-level costs and overall lower repairs, maintenance and well servicing expenses.

On a per boe basis, net operating costs decreased by 16% to \$5.89/boe in the first quarter of 2026 (Q1 2025 - \$7.00/boe) and were below the guided range of \$6.50 to \$7.25/boe. The decrease reflects the largely fixed nature of the Company's operating cost structure being allocated over higher production volumes.

Transportation costs

(\$ thousands, except as noted)	Three months ended March 31,	
	2026	2025
Oil and NGL transportation costs	4,832	5,623
Natural gas transportation costs	798	608
Total transportation costs	5,630	6,231
\$/boe	4.52	5.59

Transportation costs include clean oil trucking, NGL transportation and natural gas transportation from plant gate to commercial sales points. In the first quarter of 2026, transportation costs decreased to \$5.6 million (Q1 2025 - \$6.2 million), primarily due to a reduction in trucking rates, partially offset by higher sales volumes.

On a per boe basis, transportation costs were \$4.52/boe, a 19% decrease from the first quarter of 2025 (Q1 2025 - \$5.59/boe), and were at the low end of the guided range of \$4.50/boe to \$5.00/boe. The reductions were driven by improved trucking rates and fixed natural gas transportation commitments being allocated over higher sales volumes.

Operating netbacks

The following tables highlight Rubellite's operating netbacks for the three months ended March 31, 2026 and 2025:

(\$ thousands)	Three months ended March 31, 2026			Three months ended March 31, 2025		
	Eastern Heavy Oil	West Central	Total	Eastern Heavy Oil	West Central	Total
Revenue	59,072	7,171	66,243	60,292	6,315	66,607
Royalties	(7,942)	(808)	(8,750)	(8,123)	(1,326)	(9,449)
Net operating costs ⁽¹⁾	(6,210)	(1,125)	(7,335)	(6,094)	(1,702)	(7,796)
Transportation costs	(4,969)	(661)	(5,630)	(5,602)	(629)	(6,231)
Operating netback ⁽¹⁾	39,951	4,577	44,528	40,473	2,658	43,131
Realized loss on risk management contracts ⁽²⁾	—	—	(4,740)	—	—	(188)
Total operating netback, after risk management contracts ⁽¹⁾	39,951	4,577	39,788	40,473	2,658	42,943

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

(2) Realized loss on risk management contracts in the first quarter of 2026 is comprised of \$5.1 million loss on oil contracts and \$0.3 million gain on gas contracts (Q1 2025 - \$2.0 million loss on oil contracts and \$1.8 million gain on gas contracts).

(\$/boe)	Three months ended March 31, 2026			Three months ended March 31, 2025		
	Eastern Heavy Oil	West Central	Total	Eastern Heavy Oil	West Central	Total
Revenue	68.16	18.91	53.17	77.22	18.92	59.77
Royalties	(9.16)	(2.13)	(7.02)	(10.40)	(3.97)	(8.48)
Net operating costs ⁽¹⁾	(7.17)	(2.97)	(5.89)	(7.81)	(5.10)	(7.00)
Transportation costs	(5.73)	(1.74)	(4.52)	(7.18)	(1.88)	(5.59)
Operating netback ⁽¹⁾	46.10	12.07	35.74	51.83	7.97	38.70
Realized loss on risk management contracts ⁽²⁾	—	—	(3.80)	—	—	(0.17)
Total operating netback, after risk management contracts ⁽¹⁾	46.10	12.07	31.94	51.83	7.97	38.53

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

(2) Realized loss on risk management contracts in the first quarter of 2026 is comprised of a \$6.50/bbl loss on oil contracts and a \$0.12/Mcf gain on gas contracts (Q1 2025 - \$2.70/bbl loss on oil contracts and \$0.93/Mcf gain on gas contracts).

Rubellite's Eastern Heavy Oil operating netback decreased to \$40.0 million in the first quarter, slightly lower than the first quarter of 2025 (Q1 2025 - \$40.5 million). On a per boe basis, the operating netback decreased to \$46.10/boe in the first quarter of 2026 (Q1 2025 - \$51.83/boe) reflecting lower realized prices, partially offset by lower royalties, net operating costs and transportation costs.

Rubellite's West Central operating netback increased to \$4.6 million in the first quarter of 2026 (Q1 2025 - \$2.7 million). On a per boe basis, the West Central operating netback increased to \$12.07/boe in the first quarter of 2026 (Q1 2025 - \$7.97/boe) reflecting lower royalties associated with lower natural gas prices, and lower net operating costs and transportation costs. These cost reductions were driven by the largely fixed nature of operating and transportation expenses being allocated over higher production volumes.

Rubellite's total operating netback increased to \$44.5 million in the first quarter of 2026 (Q1 2025 - \$43.1 million). On a per boe basis, the operating netback decreased, reflecting lower realized prices due to weaker oil pricing, partially offset by reduced royalties, net operating costs and transportation costs.

In the first quarter of 2026, the operating netback, after realized losses on risk management contracts, was \$31.94/boe (Q1 2025 - \$38.53/boe).

General and administrative ("G&A") expenses

(\$ thousands, except as noted)	Three months ended March 31,	
	2026	2025
G&A expenses – before recoveries	5,992	5,643
G&A recoveries	(1,659)	(1,229)
Total G&A expenses	4,333	4,414
\$/boe	3.48	3.96

In the first quarter, G&A expenses decreased to \$4.3 million (Q1 2025 – \$4.4 million). Before overhead recoveries, G&A expenses increased to \$6.0 million (Q1 2025 – \$5.6 million), primarily due to higher people-related costs. Overhead recoveries vary from period to period based on the amount of capital expenditures incurred.

On a per boe basis, G&A costs during the first quarter of 2026 decreased to \$3.48/boe (Q1 2025 - \$3.96/boe) and were within the guided range of \$3.00 to \$3.50/boe. The decrease on a per basis reflects Rubellite's predominately fixed G&A cost structure being allocated over higher sales volumes.

Depletion

(\$ thousands, except as noted)	Three months ended March 31,	
	2026	2025
Depletion	24,370	21,658
Depreciation	539	504
Total depletion and depreciation	24,909	22,162
(\$/boe)		
Depletion	19.56	19.43
Depreciation	0.43	0.45
\$/boe	19.99	19.88

The Company calculates depletion using the net book value of the asset, future development costs associated with proved and probable reserves, salvage values on associated production equipment, as well as proved plus probable reserves. As at March 31, 2026, depletion was calculated on a \$519.7 million depletable balance (December 31, 2025 – \$514.8 million), \$435.8 million in future development costs (December 31, 2025 – \$457.6 million) and excluded an estimated \$12.4 million of salvage value (December 31, 2025 – \$12.4 million).

Depletion and depreciation expense for the first quarter of 2026 was \$24.9 million or \$19.99/boe (Q1 2025 – \$22.2 million or \$19.88/boe). The increases in depletion on both a dollar and per boe 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.

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

Impairment

Eastern Heavy Oil CGU

There were no triggers for impairment as at March 31, 2026 and December 31, 2025, and therefore no impairment test was required.

West Central CGU

There were no triggers for impairment as at March 31, 2026 and therefore no impairment test was 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

(\$ thousands)	Three months ended March 31,	
	2026	2025
Cash finance expense		
Interest on bank debt	1,445	1,812
Interest on term loan	567	567
Interest on lease liabilities	76	80
Total cash finance expense	2,088	2,459
\$/boe	1.68	2.21
Non-cash finance expense		
Amortization of debt issue costs	46	39
Accretion on decommissioning obligations	343	265
Accretion on other provision	113	140
Total non-cash finance expense	502	444
\$/boe	0.40	0.40
Finance expense	2,590	2,903

In the first quarter of 2026, total cash finance expense decreased to \$2.1 million (Q1 2025 - \$2.5 million) primarily due to lower interest rates, with the Company's interest rate on bank borrowings averaging 5.6% during the quarter (Q1 2025 - 6.0%). The interest rate on the term loan remained unchanged at 11.5%. Cash finance expense on a per boe basis decreased during the quarter due to lower cash finance expense and higher sales volumes.

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

Deferred Income Taxes

	December 31, 2025	Recognized in earnings	Recognized in equity	March 31, 2026
Deferred tax assets (liabilities):				
Property, plant and equipment	\$ (38,100)	\$ (442)	\$ —	(38,542)
Decommissioning obligations	8,198	98	—	8,296
Fair value of derivatives	(1,265)	6,891	—	5,626
Other liabilities	2,820	(828)	—	1,992
Share and debt issue costs	414	(23)	(32)	359
Non-capital losses	40,313	671	—	40,984
Deferred tax asset	\$ 12,380	\$ 6,367	\$ (32)	18,715

In the first quarter of 2026, the Company recorded a deferred income tax recovery of \$6.4 million, compared to a deferred tax expense of \$0.8 million in the first quarter of 2025. The recovery reflects a net loss before taxes, along with a decrease in unrecognized deferred tax assets. In the comparative period, higher net income before taxes was largely offset by a non-taxable gain on acquisition and a decrease in unrecognized deferred tax assets, resulting in an overall deferred tax expense.

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

<i>(\$ thousands, except as noted)</i>	March 31, 2026	December 31, 2025
Bank debt	107,837	92,583
Term loan (principal)	20,000	20,000
Adjusted working capital deficit ⁽¹⁾	20,169	30,560
Net debt ⁽¹⁾	148,006	143,143
Shares outstanding at end of period (<i>thousands</i>)	93,774	93,593
Market price at end of period (<i>\$/share</i>)	3.54	2.40
Market value of shares ⁽¹⁾	331,960	224,623
Enterprise value ⁽¹⁾	479,966	367,766
Net debt as a percentage of enterprise value ⁽¹⁾	31%	39%
Trailing twelve months adjusted funds flow ⁽¹⁾	139,506	142,073
Net debt to trailing twelve months adjusted funds flow ratio ⁽¹⁾	1.1	1.0
Q1 annualized adjusted funds flow ⁽¹⁾⁽²⁾	133,468	132,660
Net debt to Q4 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 Q1 2026 adjusted funds flow, before transaction costs, of \$33.4 million (Q1 2025 - \$35.9 million). See "Non-GAAP and Other Financial Measures" for more details.

At March 31, 2026, Rubellite had net debt of \$148.0 million, a 3% increase from \$143.1 million at December 31, 2025. During the quarter, Rubellite generated \$0.7 million of free funds flow, as adjusted funds flow of \$33.4 million exceeded total capital expenditures, including land and other spending, of \$32.7 million. Net debt increased due to payments for other obligations, including a \$3.8 million reduction of the other provision, \$0.4 million of decommissioning expenditures and \$0.7 million of cash-settled share based compensation payments, being in excess of free funds flow.

Rubellite had available liquidity at March 31, 2026 of \$30.8 million, comprised of the \$140.0 million Credit Facility Borrowing Limit, less \$107.8 million of bank borrowings and \$1.4 million of outstanding letters of credit.

Bank debt

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

As at March 31, 2026, \$107.8 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 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 during the first quarter of 2026 was 5.6% per annum (Q1 2025 - 6.0% per annum). For the period ended March 31, 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 \$0.8 million.

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

At March 31, 2026, the credit facility was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Subsequent to March 31, 2026, the Company's credit facility has been increased to \$160.0 million. The initial term was extended to May 31, 2027 and may be extended a further twelve months subject to lender approval. The next semi-annual borrowing base redetermination is scheduled on or before November 30, 2026.

Term Loan

<i>(\$ thousands)</i>	Maturity date	Interest rate	March 31, 2026		December 31, 2025	
			Principal	Carrying Amount	Principal	Carrying amount
Term loan	August 2, 2029	11.5%	20,000	19,219	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 months ending March 31, 2026, Rubellite paid \$0.6 million in cash interest payments to the holders of the term loan (Q1 2025 - \$0.6 million).

At March 31, 2026, the term loan was recorded at the present value of future cash flows, net of \$0.8 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 March 31, 2026, entities controlled or directed by the Company's Chief Executive Officer ("CEO") hold \$18.4 million of the outstanding term loan (December 31, 2025 - \$18.4 million).

Equity

At March 31, 2026, there were 93.8 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 May 8, 2026 there were 93.8 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 day 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"):

<i>(thousands)</i>	May 8, 2026
Restricted share units	3,281
Share options	3,049
Performance share units	2,453
Perpetual awards ⁽¹⁾	1,769
Total	10,552

(1) Of the 1.8 million share based awards under the Acquired Plans outstanding, 1.1 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 May 8, 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	5,000 bbl/d	May 2026	WTI (US\$/bbl)	Swap - sold	\$67.51
Crude Oil	5,000 bbl/d	Jun 2026	WTI (US\$/bbl)	Swap - sold	\$66.96
Crude Oil	4,800 bbl/d	Jul 2026 - Sep 2026	WTI (US\$/bbl)	Swap - sold	\$66.19
Crude Oil	4,900 bbl/d	Oct 2026 - Dec 2026	WTI (US\$/bbl)	Swap - sold	\$68.11
Crude Oil	3,450 bbl/d	Jan 2027 - Dec 2027	WTI (US\$/bbl)	Swap - sold	\$70.72
Crude Oil	1,200 bbl/d	Jan 2028 - Dec 2028	WTI (US\$/bbl)	Swap - sold	\$70.00
Crude Oil	5,500 bbl/d	May 2026 - Jun 2026	WCS Differential (US\$/bbl)	Swap - sold	(\$12.44)
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)

As at May 8, 2026, Rubellite had the following natural gas commodity risk management contracts:

Commodity	Volumes Sold	Term	Reference/Index	Contract Traded Bought/Sold	Average Price (\$/GJ)
Natural gas	5,275 GJ/d	May 2026	AECO 5A (CAD\$/GJ)	Swap - sold	\$2.61
Natural gas	5,275 GJ/d	Jun 2026	AECO 5A (CAD\$/GJ)	Swap - sold	\$3.03
Natural gas	5,275 GJ/d	Jul 2026 - Oct 2026	NYMEX (US\$/GJ)	Swap - sold	\$3.89

Foreign exchange risk management

As at May 8, 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	Apr - Dec 2026	1.4066
Average rate forward (CAD\$/US\$) ⁽¹⁾	\$5,000,000 US\$/month	Apr - Dec 2026	1.3890

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

COMMITMENTS AND CONTRACTUAL OBLIGATIONS

The Company has a drilling commitment on certain GORR lands that must be fulfilled by September 28, 2026 (the "Commitment Date"). If WTI settles below USD \$60.00/bbl for a period of thirty consecutive days, the agreement shall automatically extend for an additional 30 days. 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 March 31, 2026, the Company spud 36 (36.0 net) of the 59 (59.0 net) wells that are required to meet the drilling commitment. Subsequent to March 31, 2026, the Company spud an additional 5 (5.0 net) wells for a total of 41 (41.0 net) wells required to meet the drilling commitment.

PROVISIONS

Decommissioning obligations

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

The increase in the provision due to the passage of time, which is referred to as accretion, is recognized as non-cash finance expense in the consolidated statements of income (loss) and comprehensive income (loss). 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.

<i>(\$ thousands)</i>	March 31, 2026	December 31, 2025
Decommissioning obligations – current	1,340	1,340
Decommissioning obligations – non-current	34,729	34,302
Total decommissioning obligations	36,069	35,642

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

<i>(\$ thousands, except as noted)</i>	March 31, 2026	December 31, 2025
Undiscounted obligations	49,447	49,432
Average risk-free rate	3.9%	3.9%
Inflation rate	2.1%	2.0%
Expected timing of settling obligations	1 to 25 years	1 to 25 years

Other provision

<i>(\$ thousands)</i>	March 31, 2026	December 31, 2025
Other provision – current	3,750	3,750
Other provision – non-current	7,917	11,554
Total other provision⁽¹⁾⁽²⁾	11,667	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:

<i>(\$ thousands, except as noted)</i>	March 31, 2026	December 31, 2025
Undiscounted obligations	12,441	16,191
Average risk-free rate	3.0%	3.0%
Expected timing of settling obligations	4.0 years	4.3 years

The Company is required to make annual principal 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. 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:

(\$ thousands)	Three months ended March 31,	
	2026	2025
Net cash flows used in investing activities	(39,197)	(24,383)
Change in non-cash working capital	(6,533)	549
Total capital expenditures	(32,664)	(24,932)
Property, plant and equipment additions	(28,600)	(21,858)
Exploration and evaluation additions	(3,971)	(2,933)
Corporate expenditures	(93)	(141)
Total capital expenditures	(32,664)	(24,932)
Add back:		
Corporate and other	93	141
Geological and geophysical	370	405
Land	875	2,102
Exploration and development spending ⁽¹⁾	(31,326)	(22,284)

(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.

(\$ thousands, except per boe amounts)	\$/boe	Three months ended March 31,		
		2026	2025	
Net operating costs	5.89	7,335	7.00	7,796
Transportation	4.52	5,630	5.59	6,231
General and administrative	3.48	4,333	3.96	4,414
Cash finance expense	1.68	2,088	2.21	2,459
Cash costs	15.57	19,386	18.76	20,900

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

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

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

(\$ thousands, except per boe amounts)	Three months ended March 31,	
	2026	2025
Other income	133	102
Production and operating	7,468	7,898
Less: processing income	(133)	(102)
Net operating costs	7,335	7,796
\$/boe	5.89	7.00

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:

<i>(\$ thousands)</i>	As of March 31, 2026	As of December 31, 2025
Current assets	37,432	35,181
Current liabilities	(97,311)	(70,413)
Working capital deficit	59,879	35,232
Risk management contracts – current asset	1,110	5,828
Risk management contracts – current liability	(27,915)	(327)
Lease liability - current liability	(385)	(389)
Share based compensation liability - current liability	(7,430)	(4,694)
Decommissioning obligations – current liability	(1,340)	(1,340)
Other provision - current liability	(3,750)	(3,750)
Adjusted working capital deficit ⁽¹⁾	20,169	30,560
Bank indebtedness	107,837	92,583
Term loan (principal)	20,000	20,000
Net debt ⁽²⁾	148,006	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:

<i>(\$ thousands, except as noted)</i>	Three months ended March 31,	
	2026	2025
Net cash flows from operating activities	24,579	27,135
Change in non-cash working capital	3,866	4,080
Cash-settled share based compensation	729	196
Other provision settled	3,750	3,750
Decommissioning obligations settled	443	773
Adjusted funds flow	33,367	35,934
Adjusted funds flow per share - basic	0.36	0.39
Adjusted funds flow per share - diluted	0.36	0.38
Adjusted funds flow per boe	26.78	32.24

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 its most directly comparable GAAP measure 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:

<i>(\$ thousands)</i>	Three months ended March 31,	
	2026	2025
Adjusted funds flow	33,367	35,934
Total capital expenditures	(32,664)	(24,932)
Free funds flow	703	11,002

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

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

Non-GAAP Financial Ratios

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

Average realized prices after risk management contracts: 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 after transaction costs.

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

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

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 & 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 barrel basis.

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

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

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

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

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

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

"Royalties as a percentage of revenue" is comprised of royalties, as determined in accordance with IFRS, divided by 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 expense per boe" is comprised of net operating expense (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 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 crude oil production relative to the Western Canadian Select reference price (CAD\$/bbl), prior to any price or risk management activities.

INTERNAL CONTROLS AND PROCEDURES

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

There were no changes in the Company's DC&P or ICFR during the period beginning January 1, 2026 and ending March 31, 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, Frog Lake and East Edson, 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; 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

<i>(\$ thousands, except as noted)</i>	Q1 2026	Q4 2025	Q3 2025	Q2 2025
Financial				
Oil and natural gas revenue	66,243	56,261	58,290	60,542
Net income (loss) and comprehensive income (loss)	(23,071)	9,700	5,646	16,051
Per share – basic ⁽²⁾	(0.25)	0.10	0.06	0.17
Per share – diluted ⁽²⁾	(0.25)	0.10	0.06	0.17
Total assets	597,152	578,509	558,709	561,545
Cash flow from operating activities	24,579	30,900	34,953	35,808
Adjusted funds flow, after transaction costs ⁽¹⁾⁽⁴⁾	33,367	33,165	35,663	37,311
Per share – basic ⁽¹⁾⁽²⁾	0.36	0.35	0.38	0.40
Per share – diluted ⁽¹⁾⁽²⁾	0.36	0.34	0.37	0.39
Total capital expenditures ⁽¹⁾⁽⁵⁾	32,664	39,037	35,365	31,168
Common shares (thousands)				
Weighted average – basic	93,590	94,488	93,700	93,279
Weighted average – diluted	93,590	97,478	96,311	95,074
Sales Production				
Heavy oil (bbl/d)	8,641	8,295	8,338	8,637
Natural gas (Mcf/d)	28,532	25,884	20,975	20,522
NGL (bbl/d)	447	433	288	368
Daily average sales production (boe/d)	13,843	13,042	12,122	12,425
Rubellite average realized price⁽¹⁾				
Oil (\$/bbl)	74.42	63.32	72.40	69.98
Natural gas (\$/Mcf)	2.27	2.47	0.66	1.93
NGL (\$/bbl)	63.10	51.93	56.12	57.92
Total average realized price (\$/boe)	53.17	46.89	52.27	53.54

(\$ thousands, except as noted)	Q1 2025	Q4 2024	Q3 2024	Q2 2024
Financial				
Oil and natural gas revenue	66,607	59,081	43,682	35,798
Net income (loss) and comprehensive income (loss)	1,160	26,747	15,010	12,368
Per share – basic ⁽²⁾	0.01	0.31	0.23	0.20
Per share – diluted ⁽²⁾	0.01	0.30	0.23	0.19
Total assets	551,889	562,612	432,836	281,549
Cash flow from operating activities	27,135	39,402	19,973	19,916
Adjusted funds flow, after transaction costs ⁽¹⁾⁽⁴⁾	35,934	31,632	23,029	20,664
Per share – basic ⁽¹⁾⁽²⁾	0.39	0.36	0.35	0.33
Per share – diluted ⁽¹⁾⁽²⁾	0.38	0.36	0.35	0.33
Total capital expenditures ⁽¹⁾	24,932	35,537	36,650	23,927
Acquisitions ⁽³⁾	—	68,467	62,732	—
Common shares (thousands)				
Weighted average – basic	92,930	87,655	65,834	62,494
Weighted average – diluted	95,068	88,546	66,571	63,446
Production				
Heavy oil (bbl/d)	8,339	7,754	5,954	4,503
Natural gas (Mcf/d)	22,038	14,140	—	—
NGL (bbl/d)	371	275	—	—
Daily average sales production (boe/d)	13,383	10,386	5,954	4,503
Rubellite average realized price⁽¹⁾				
Oil (\$/bbl)	80.03	76.97	79.75	87.35
Natural gas (\$/Mcf)	2.16	2.01	—	—
NGL (\$/bbl)	67.54	61.32	—	—
Total average realized price (\$/bbl)	59.77	61.83	79.75	87.35

(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.

(5) 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.

Oil and natural gas revenue has ranged between \$35.8 million and \$66.6 million over the prior eight quarters largely due to increasing sales volumes from 4,503 boe/d to 13,843 boe/d, partially offset by volatility in commodity pricing. Net income (loss) has ranged between a loss of \$23.1 million and income of \$26.7 million primarily due to increased production, corporate acquisitions and dispositions, volatility of commodity prices and its impact on revenue, royalties, realized and unrealized risk management contract gains and losses and deferred income taxes.