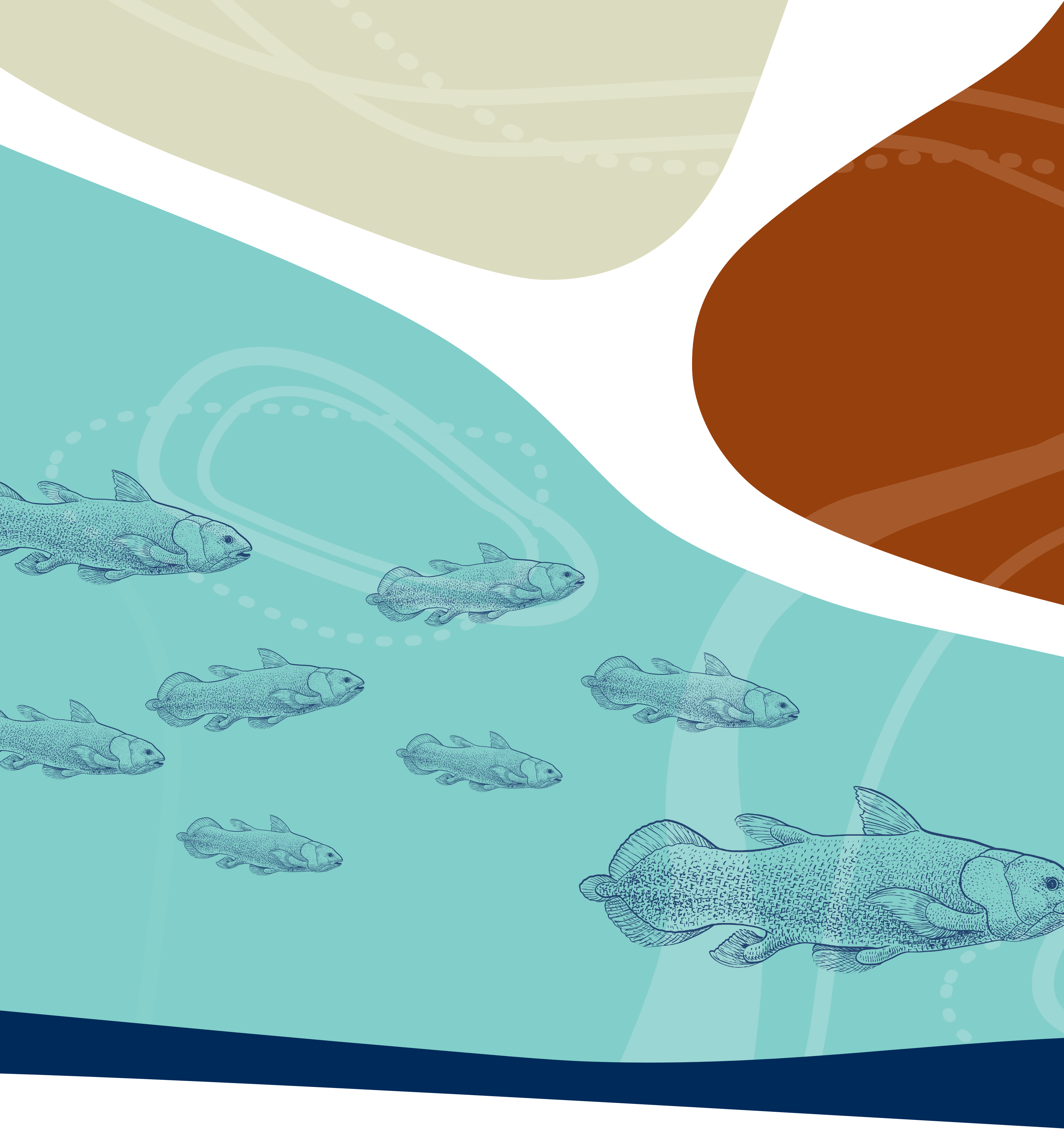

2025
ANNUAL REPORT

COELACANTH
ENERGY INC.

ABOUT COELACANTH

The name Coelacanth and success go hand-in-hand. Coelacanth (pronounced see-luh-kanth) is a prehistoric fish dating back 410 million years. This species was thought to be long extinct – until discovered off the coast of Indonesia in 1938. It is a survivor!

Coelacanth fossils are common to the Montney formation, where our oil & gas exploration and development company operates and has identified extensive opportunities. In a sea of sameness, our brand is dynamic, modern, distinct… and defies expectation. A true reflection of the company and the people behind it.

COELACANTH
ENERGY INC.

Q4 2025 FINANCIAL AND OPERATING RESULTS

2025 HIGHLIGHTS

- Completed construction of its Two Rivers East facility and pipelines to connect the 5-19 pad wells for a Q2 2025 on-stream date.
- Drilled and completed three Lower Montney wells on its 5-19 pad at Two Rivers East in Q4 2025.
- Increased oil and natural gas production 271% to 4,027 boe/d in Q4 2025 from 1,084 boe/d in Q4 2024. Exit 2025 production was approximately 5,100 boe/d and exit Q1 2026 production was approximately 8,000 boe/d with the ramp up of new wells on production on its 5-19 pad at Two Rivers East.
- Entered into an $80.0 million credit facility with current lender to replace its previous credit facilities. Subsequent to December 31, 2025, on April 20, 2026, this credit facility was amended and restated to extend and increase the credit facility to $90.0 million (the “Amended Credit Facility”).

FINANCIAL RESULTS	**Three Months Ended December 31**			**Year Ended December 31**		
($000s, except per share amounts)	**2025**	2024	% Change	**2025**	2024	% Change
Oil and natural gas sales	**11,603**	4,544	155	**30,469**	13,736	122
Cash flow from operating activities	**4,852**	3,157	54	**8,906**	2,203	304
Per share - basic and diluted (1)	**0.01**	0.01	-	**0.02**	-	100
Adjusted funds flow (2)	**2,310**	382	505	**2,843**	1,515	88
Per share - basic and diluted	**-**	-	-	**0.01**	-	100
Net loss	**(2,181)**	(2,903)	(25)	**(11,026)**	(8,897)	24
Per share - basic and diluted	**-**	(0.01)	(100)	**(0.02)**	(0.02)	-
Capital expenditures (3)	**34,536**	64,952	(47)	**80,614**	84,497	(5)
Adjusted working capital deficiency (4)				**(37,934)**	(18,527)	105
Net debt (5)				**(76,035)**	(18,527)	310
Common shares outstanding (000s)						
Weighted average - basic and diluted	**533,133**	530,398	1	**532,448**	529,804	-
End of period - basic				**533,465**	530,670	1
End of period - fully diluted				**590,777**	615,930	(4)

(1) Supplemental financial measure. Please refer to the “Non-GAAP and Other Financial Measures” section in the MD&A for more details.

(2) Adjusted funds flow and adjusted funds flow per share do not have any standardized meaning prescribed by IFRS Accounting Standards (“IFRS”) and therefore may not be comparable to similar measures used by other companies. Please refer to the “Non-GAAP and Other Financial Measures” section in the MD&A for more details and the “Cash Flow From Operating Activities and Adjusted Funds Flow” section in the MD&A for a reconciliation from cash flow from operating activities.

(3) Capital expenditures does not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. Please refer to the “Non-GAAP and Other Financial Measures” section in the MD&A for more details.

(4) Adjusted working capital deficiency is a capital management measure calculated as current assets and restricted cash deposits less current liabilities, excluding the current portion of decommissioning obligations and other obligations. Please refer to the “Non-GAAP and Other Financial Measures” section in the MD&A for more details.

(5) Net debt is a capital management measure calculated as the non-current portion of the credit facility and adjusted working capital deficiency. Please refer to the “Non-GAAP and Other Financial Measures” section in the MD&A for more details.

OPERATING RESULTS [1]	Three Months Ended December 31			Year Ended December 31		
	2025	2024	% Change	**2025**	2024	% Change
Daily production [2]						
Oil and condensate (bbls/d)	**1,151**	473	143	**816**	320	155
Other NGLs (bbls/d)	**165**	29	469	**77**	34	126
Oil and NGLs (bbls/d)	**1,316**	502	162	**893**	354	152
Natural gas (mcf/d)	**16,268**	3,490	366	**8,626**	3,648	136
Oil equivalent (boe/d)	**4,027**	1,084	271	**2,331**	962	142
Oil and natural gas sales						
Oil and condensate ($/bbl)	**73.36**	87.06	(16)	**78.15**	89.46	(13)
Other NGLs ($/bbl)	**20.66**	33.28	(38)	**24.29**	33.22	(27)
Oil and NGLs ($/bbl)	**66.78**	83.97	(20)	**73.83**	83.99	(12)
Natural gas ($/mcf)	**2.35**	2.07	14	**2.03**	2.14	(5)
Oil equivalent ($/boe)	**31.32**	45.57	(31)	**35.82**	39.01	(8)
Operating netback and net loss ($/boe)						
Oil and natural gas sales	**31.32**	45.57	(31)	**35.82**	39.01	(8)
Royalties	**(4.08)**	(8.22)	(50)	**(6.15)**	(7.66)	(20)
Operating expenses	**(7.45)**	(7.88)	(5)	**(8.26)**	(9.47)	(13)
Net transportation expenses [3]	**(2.67)**	(5.01)	(47)	**(3.28)**	(4.04)	(19)
Operating netback [4]	**17.12**	24.46	(30)	**18.13**	17.84	2
Depletion and depreciation	**(9.46)**	(10.76)	(12)	**(10.56)**	(13.59)	(22)
General and administrative expenses	**(6.01)**	(15.46)	(61)	**(7.78)**	(14.34)	(46)
Share based compensation	**(2.39)**	(7.08)	(66)	**(5.21)**	(11.12)	(53)
Loss on lease termination	**-**	(2.02)	(100)	**-**	(0.57)	(100)
Finance expense	**(4.91)**	(18.02)	(73)	**(6.86)**	(6.33)	8
Finance income	**0.11**	3.65	(97)	**0.31**	8.23	(96)
Unutilized transportation	**(0.36)**	(3.88)	(91)	**(0.98)**	(5.37)	(82)
Net loss	**(5.90)**	(29.11)	(80)	**(12.95)**	(25.25)	(49)

(1) "bbls" and "bbls/d" refers to barrels and barrels per day, "mcf" and "mcf/d" refers to thousand cubic feet and thousand cubic feet per day, and "boe" and "boe/d" refers to barrels of oil equivalent and barrels of oil equivalent per day. Disclosure provided herein in respect of a boe may be misleading, particularly if used in isolation. A boe conversion rate of six thousand cubic feet of natural gas to one barrel of oil equivalent has been used for the calculation of boe amounts in the MD&A. This boe conversion rate is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(2) "Natural gas" refers to shale gas; "Oil and condensate" refers to condensate and tight oil combined; "Other NGLs" refers to butane, propane and ethane combined; "Oil and NGLs" refers to tight oil, and NGLs combined; "Oil equivalent" refers to the total oil equivalent of shale gas, tight oil, and NGLs combined, using the conversion rate of six thousand cubic feet of shale gas to one barrel of oil equivalent as described above. Readers are referred to the "Product Types" section in the MD&A for a complete breakdown of sales volumes for applicable periods by specific product types of shale gas, tight oil, and NGLs.

(3) Net transportation expenses does not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. Please refer to the "Non-GAAP and Other Financial Measures" section in the MD&A for more details and the "Net Transportation Expenses" section in the MD&A for reconciliations from transportation expenses.

(4) Operating netback does not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. Please refer to the "Non-GAAP and Other Financial Measures" section in the MD&A for more details and the "Operating Netback" section in the MD&A for reconciliations from net loss.

MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A")

April 21, 2026

The MD&A should be read in conjunction with the audited financial statements and related notes for the years ended December 31, 2025 and 2024. The audited financial statements and financial data contained in the MD&A have been prepared in accordance with IFRS Accounting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). All dollar amounts are expressed in Canadian currency, unless otherwise noted.

DESCRIPTION OF BUSINESS

Coelacanth Energy Inc. ("Coelacanth" or the "Company") is an oil and natural gas company, actively engaged in the acquisition, development, exploration, and production of oil and natural gas reserves in northeastern British Columbia, Canada. The Company trades on the TSX Venture Exchange ("TSXV") under the symbol "CEI".

OIL AND GAS TERMS

The Company uses the following frequently recurring oil and gas industry terms in the MD&A:

Liquids

Bbls	Barrels
Bbls/d	Barrels per day
NGLs	Natural gas liquids (includes condensate, pentane, butane, propane, and ethane)
Condensate	Pentane and heavier hydrocarbons

Natural Gas

Mcf	Thousands of cubic feet
Mcf/d	Thousands of cubic feet per day
MMcf/d	Millions of cubic feet per day
MMbtu	Million of British thermal units
MMbtu/d	Million of British thermal units per day
GJ	Gigajoules
GJ/d	Gigajoules per day

Oil Equivalent

Boe	Barrels of oil equivalent
Boe/d	Barrels of oil equivalent per day

Disclosure provided herein in respect of a boe may be misleading, particularly if used in isolation. A boe conversion rate of six thousand cubic feet of natural gas to one barrel of oil equivalent has been used for the calculation of boe amounts in the MD&A. This boe conversion rate is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

NOTE REGARDING PRODUCT TYPES

The Company uses the following references to sales volumes in the MD&A:

Natural gas refers to shale gas
Oil and condensate refers to condensate and tight oil combined
Other NGLs refers to butane, propane and ethane combined
Oil and NGLs refers to tight oil and NGLs combined
Oil equivalent refers to the total oil equivalent of shale gas, tight oil, and NGLs combined, using the conversion rate of six thousand cubic feet of shale gas to one barrel of oil equivalent as described above.

Readers are referred to the "Product Types" section for a complete breakdown of sales volumes for applicable periods by specific product types of shale gas, tight oil, and NGLs.

NON-GAAP AND OTHER FINANCIAL MEASURES

This MD&A refers to certain measures that are not determined in accordance with IFRS (or "GAAP"). 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 alternatives to, or more meaningful than, financial measures that are determined in accordance with IFRS as indicators of the Company's performance. Management believes that the presentation of these non-GAAP and other financial measures provides useful information to shareholders and investors in understanding and evaluating the Company's ongoing operating performance, and the measures provide increased transparency to better analyze the Company's performance against prior periods on a comparable basis.

Non-GAAP Financial Measures

Adjusted funds flow
Management uses adjusted funds flow to analyze performance and considers it a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments and abandonment obligations and to repay debt. Adjusted funds flow is a non-GAAP financial measure and has been defined by the Company as cash flow from operating activities excluding the change in non-cash working capital related to operating activities, movements in restricted cash deposits and expenditures on decommissioning

obligations. Management believes the timing of collection, payment or incurrence of these items involves a high degree of discretion and as such may not be useful for evaluating the Company's cash flows. Adjusted funds flow is reconciled from cash flow from operating activities under the heading "Cash Flow From Operating Activities and Adjusted Funds Flow".

Net transportation expenses
Management considers net transportation expenses an important measure as it demonstrates the cost of utilized transportation related to the Company's production. Net transportation expenses is calculated as transportation expenses less unutilized transportation and is calculated as follows:

	Three Months Ended December 31		**Year Ended December 31**	
($000s)	**2025**	2024	**2025**	2024
Transportation expenses	**1,120**	887	**3,618**	3,313
Unutilized transportation	**(132)**	(387)	**(831)**	(1,891)
Net transportation expenses (non-GAAP)	**988**	500	**2,787**	1,422

Operating netback
Management considers operating netback an important measure as it demonstrates its profitability relative to current commodity prices. Operating netback is calculated as oil and natural gas sales less royalties, operating expenses, and net transportation expenses and is calculated as follows:

	Three Months Ended December 31		**Year Ended December 31**	
($000s)	**2025**	2024	**2025**	2024
Oil and natural gas sales	**11,603**	4,544	**30,469**	13,736
Royalties	**(1,511)**	(820)	**(5,236)**	(2,698)
Operating expenses	**(2,759)**	(786)	**(7,031)**	(3,335)
Net transportation expenses	**(988)**	(500)	**(2,787)**	(1,422)
Operating netback (non-GAAP)	**6,345**	2,438	**15,415**	6,281

Capital expenditures
Coelacanth utilizes capital expenditures as a measure of capital investment on property, plant, and equipment, exploration and evaluation assets and property acquisitions compared to its annual budgeted capital expenditures. Capital expenditures are calculated as follows:

	Three Months Ended December 31		**Year Ended December 31**	
($000s)	**2025**	2024	**2025**	2024
Capital expenditures – property, plant, and equipment	**30,615**	233	**35,891**	1,206
Capital expenditures – exploration and evaluation assets	**3,921**	64,719	**44,723**	83,291
Capital expenditures (non-GAAP)	**34,536**	64,952	**80,614**	84,497

Capital Management Measures

Adjusted working capital deficiency and net debt
Management uses adjusted working capital deficiency and net debt as measures to assess the Company's financial position. Adjusted working capital is calculated as current assets and restricted cash deposits less current liabilities, excluding the current portion of decommissioning obligations and other obligations. Net debt includes adjusted working capital deficiency and non-current portion of the credit facility. Refer to the calculation of adjusted working capital deficiency and net debt and reconciliation to working capital under the heading "Liquidity and Capital Resources".

Non-GAAP Financial Ratios

Adjusted funds flow per share
Adjusted funds flow per share is a non-GAAP financial ratio, calculated using adjusted funds flow and the same weighted average basic and diluted shares used in calculating net loss per share.

Net transportation expenses per boe
The Company utilizes net transportation expenses per boe to assess the per unit cost of utilized transportation related to the Company's production. Net transportation expenses per boe is calculated as net transportation expenses divided by total production for the applicable period. Net transportation expenses per boe is reconciled to transportation expenses per boe under the heading "Net Transportation Expenses".

Operating netback per boe
The Company utilizes operating netback per boe to assess the operating performance of its oil and natural gas assets on a per unit of production basis. Operating netback per boe is calculated as operating netback divided by total production for the applicable period. Operating netback per boe is reconciled to net loss per boe under the heading "Operating Netback".

Supplementary Financial Measures

The supplementary financial measures used in this MD&A (primarily average sales price per product type, royalty rates, and certain per boe and per share figures) are either a per unit disclosure of a corresponding GAAP measure, or a component of a corresponding GAAP measure, presented in the financial statements. Supplementary financial measures that are disclosed on a per unit basis are calculated by dividing the aggregate GAAP measure (or component thereof) by the applicable unit for the period. Supplementary financial measures that are disclosed on a component basis of a corresponding GAAP measure are a granular representation of a financial statement line item and are determined in accordance with GAAP.

OPERATIONS UPDATE

Coelacanth had a very active 2025 investing over $80.0 million to further its large Montney Project at Two Rivers in northeast British Columbia. Over half the capital was spent on completing the facilities and gathering lines to bring on the 5-19 pad wells previously drilled and tested. Remaining capital expenditures were for drilling three additional Montney pad wells at 5-19. Throughout Q4 2025 and Q1 2026, wells were systematically placed on production to achieve a production rate of 8,000 boe/d in late March 2026 with additional wells anticipated to be placed on production by end of April 2026 as previously disclosed. As part of an expanded role and in conjunction with the recent production increases, Coelacanth has also promoted Dan Rach to the role of VP Production.

With the construction of the new infrastructure completed with excess capacity available for growth, Coelacanth can focus on go-forward capital in 2026 and 2027 primarily on drilling. Coelacanth anticipates drilling a new 5 or 6 well development pad in summer 2026 and start further delineation of the large Montney resource that has stacked Montney zones.

Reserves were conservatively booked with less than 8% of the lands with reserves booked in the Lower Montney and less than 2% of the lands with reserves booked in the Upper Montney. This leaves significant upside for future bookings pending successful delineation of the asset base both aerially across the lands and vertically through the Montney stack.

The Amended Credit Facility completed on April 20, 2026 to increase and extend the Company's bank credit facility to $90.0 million plus the recently announced equity raise of $80.0 million anticipated to close on or around May 6, 2026, will allow Coelacanth to systematically work through its business plan of not only increasing production year over year but proving out the resource to understand the ultimate scale of this project.

We look forward to reporting on future developments as they arise.

SUMMARY OF FINANCIAL RESULTS

	Three Months Ended December 31			**Year Ended December 31**		
($000s, except per share amounts)	**2025**	2024	% Change	**2025**	2024	2023
Oil and natural gas sales	**11,603**	4,544	155	**30,469**	13,736	6,663
Cash flow from (used in) operating activities	**4,852**	3,157	54	**8,906**	2,203	(4,234)
Per share - basic and diluted (4)	**0.01**	0.01	-	**0.02**	-	(0.01)
Adjusted funds flow (used) (1)	**2,310**	382	505	**2,843**	1,515	(333)
Per share - basic and diluted	**-**	-	-	**0.01**	-	(-)
Net loss	**(2,181)**	(2,903)	(25)	**(11,026)**	(8,897)	(6,573)
Per share - basic and diluted	**-**	(0.01)	(100)	**(0.02)**	(0.02)	(0.01)
Total assets				**275,800**	213,038	208,994
Total long-term liabilities				**65,063**	7,775	7,721
Adjusted working capital (deficiency) (2)				**(37,934)**	(18,527)	68,024
Net debt (3)				**(76,035)**	(18,527)	68,024

(1) Adjusted funds flow (used) and adjusted funds flow (used) per share do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. Please refer to the "Non-GAAP and Other Financial Measures" section for more details and the "Cash Flow From Operating Activities and Adjusted Funds Flow" section for a reconciliation from cash flow from operating activities.

(2) Adjusted working capital (deficiency) is a capital management measure calculated as current assets and restricted cash deposits less current liabilities, excluding the current portion of decommissioning obligations and other obligations. Please refer to the "Non-GAAP and Other Financial Measures" section for more details.

(3) Net debt is a capital management measure calculated as the non-current portion of the credit facility and adjusted working capital deficiency. Please refer to the "Non-GAAP and Other Financial Measures" section for more details.

(4) Supplemental financial measure. Please refer to the "Non-GAAP and Other Financial Measures" section for more details.

Oil and natural gas sales increased in 2025 compared to 2024 as a result of the initiation of commercial production at Two Rivers East part way through June 2025. Cash flow and adjusted funds flow increased mainly as a result of increased production partially offset by increased interest expense, lower interest income and payments on financing obligation.

Oil and natural gas sales, cash flow from operating activities, and adjusted funds flow increased in 2024 compared to 2023 mainly due to an increase in oil and natural gas production stemming from two new wells at Two Rivers West placed on production in Q4 2023.

Net loss increased in 2025 compared to 2024 mainly as the result of increased depletion and depreciation resulting from increased production and cost base of property, plant and equipment, partially offset by increased adjusted funds flow.

Net loss increased in 2024 compared to 2023 mainly as the result of $1.7 million of third party fees to secure the initial one-year term of a $45.0 million credit facility and increased depletion and depreciation expense resulting from increased production.

Adjusted working capital deficiency increased in 2025 compared to 2024 and 2023 as the result of building out the required infrastructure and commencing its pad drilling program at Two Rivers East.

PRODUCTION	**Three Months Ended December 31**			**Year Ended December 31**		
	2025	2024	% Change	**2025**	2024	% Change
Average Daily Production (1)						
Oil and condensate (bbls/d)	**1,151**	473	143	**816**	320	155
Other NGLs (bbls/d)	**165**	29	469	**77**	34	126
Oil and NGLs (bbls/d)	**1,316**	502	162	**893**	354	152
Natural gas (mcf/d)	**16,268**	3,490	366	**8,626**	3,648	136
Oil equivalent (boe/d)	**4,027**	1,084	271	**2,331**	962	142

(1) "Natural gas" refers to shale gas; "Oil and condensate" refers to condensate and tight oil combined; "Other NGLs" refers to butane, propane and ethane combined; "Oil and NGLs" refers to tight oil and NGLs combined; "Oil equivalent" refers to the total oil equivalent of shale gas, tight oil, and NGLs combined, using the conversion rate of six thousand cubic feet of shale gas to one barrel of oil equivalent. Readers are referred to the "Product Types" section for a complete breakdown of sales volumes for applicable periods by specific product types of shale gas, tight oil, and NGLs.

Daily production increased to 4,027 boe/d and 2,331 boe/d for the three months and year ended December 31, 2025, respectively, from 1,084 boe/d and 962 boe/d for the comparative periods in 2024. The increase in production was the result of the initiation of commercial production at Two Rivers East part way through June 2025.

Coelacanth's production profile for the fourth quarter of 2025 was comprised of lower oil and NGLs content when compared to the comparative quarter in 2024 as the result of increased oil content during the testing phase of early successful drilling at Two Rivers East in Q4 2024 when overall production was significantly lower than in Q4 2025. The Q4 2025 weighting was 67% natural gas (Q4 2024 - 54%) and 33% oil and NGLs (Q4 2024 - 46%). As the wells mature, it is expected that the production mix will become more gas weighted.

OIL AND NATURAL GAS SALES	**Three Months Ended December 31**			**Year Ended December 31**		
($000s)	**2025**	2024	% Change	**2025**	2024	% Change
Oil and condensate	**7,768**	3,791	105	**23,382**	10,465	123
Other NGLs	**313**	88	256	**685**	419	63
Oil and NGLs	**8,081**	3,879	108	**24,067**	10,884	121
Natural gas	**3,522**	665	430	**6,402**	2,852	124
Total	**11,603**	4,544	155	**30,469**	13,736	122
Average Sales Price						
Oil and condensate ($/bbl)	**73.36**	87.06	(16)	**78.15**	89.46	(13)
Other NGLs ($/bbl)	**20.66**	33.28	(38)	**24.29**	33.22	(27)
Oil and NGLs ($/bbl)	**66.78**	83.97	(20)	**73.83**	83.99	(12)
Natural gas production sales and transportation revenue ($/mcf)	**2.35**	2.07	14	**2.03**	2.14	(5)
Combined ($/boe)	**31.32**	45.57	(31)	**35.82**	39.01	(8)

Revenue totaled $11.6 million and $30.5 million for the three months and year ended December 31, 2025, respectively, compared to $4.5 million and $13.7 million for the comparative periods in 2024. The increase in revenue was mainly the result of the increase in production resulting from initiation of commercial production at Two Rivers East part way through June 2025.

The following table outlines the Company's realized wellhead prices and industry benchmarks:

Commodity Pricing	Three Months Ended December 31			Year Ended December 31		
	2025	2024	% Change	**2025**	2024	% Change
Oil and NGLs						
Corporate price ($CDN/bbl)	**66.78**	83.97	(20)	**73.83**	83.99	(12)
Canadian light sweet ($CDN/bbl)	**76.54**	92.69	(17)	**85.66**	98.13	(13)
West Texas Intermediate ("WTI") ($US/bbl)	**59.14**	70.27	(16)	**64.81**	75.73	(14)
Natural gas						
Corporate price ($CDN/mcf)	**2.35**	2.07	14	**2.03**	2.14	(5)
AECO price ($CDN/mcf)	**2.28**	1.48	54	**1.69**	1.39	22
Westcoast Station 2 ($CDN/mcf)	**1.94**	0.95	104	**0.99**	1.09	(9)
Chicago City Gate ($US/mmbtu)	**3.36**	2.51	34	**3.25**	2.19	48
Exchange rate						
CDN/US dollar exchange rate	**0.7171**	0.7147	-	**0.7158**	0.7301	(2)

Future prices received from the sale of the products may fluctuate as a result of market factors. Differences between corporate and benchmark prices can be the result of quality differences (higher or lower API oil and higher or lower heat content natural gas), sour content, the mix of sales points and marketing contracts negotiated for products, the mix of oil and NGLs, and various other factors. Coelacanth's differences are mainly the result of higher heat content natural gas production that is priced higher than AECO reference prices as well as the diversification of sales points and marketing contracts for products.

The Company's corporate average oil and NGLs prices were 87.2% and 86.2% of Canadian light sweet prices for the three months and year ended December 31, 2025, respectively, consistent with 90.6% and 85.6% for the comparative periods in 2024. Coelacanth's liquids mix during the fourth quarter of 2025 was approximately 88% light oil, condensate and pentanes, 7% butane and 5% propane (Q4 2024 - 94% light oil, condensate and pentanes, 3% butane and 3% propane).

Corporate average natural gas prices were 121.1% and 205.1% of Westcoast Station 2 price for the three months and year ended December 31, 2025, respectively, compared to 217.9% and 196.3% for the comparative periods in 2024. The decrease in the fourth quarter of 2025 compared to the fourth quarter of 2024 was due to a higher percentage of the Company's natural gas production being sold under lower priced Westcoast Station 2 contracts than Chicago contracts. The Company has contracted 1.5 mmcf/d of natural gas to be delivered to Chicago with the remainder being delivered to Westcoast Station 2.

At December 31, 2025, the Company had the following commodity price contracts outstanding:

Commodity	Period	Type of Contract	Quantity	Contract Price
Oil	January 1, 2026 - April 30, 2026	Physical Sales	500 bbls/d	WTI CDN $86.86/bbl
Natural Gas	January 1, 2026 - March 31, 2026	Physical Sales	10,000 GJ/d	Westcoast Station 2 CDN $2.49/GJ

Subsequent to December 31, 2025, the Company entered into the following commodity price contracts:

Commodity	Period	Type of Contract	Quantity	Contract Price
Oil	May 1, 2026 - June 30, 2026	Physical Sales	500 bbls/d	WTI CDN $85.69/bbl

The Company accounts for any physical sales contracts as executory contracts and as such are not recorded at fair value on the statement of financial position. Settlements on these physical sales contracts are recognized in oil and natural gas sales.

ROYALTIES	Three Months Ended December 31			Year Ended December 31		
($000s)	**2025**	2024	% Change	**2025**	2024	% Change
Oil and NGLs	**1,312**	779	68	**4,840**	2,424	100
Natural gas	**199**	41	385	**396**	274	45
Total	**1,511**	820	84	**5,236**	2,698	94
Average Royalty Rate (% of sales)						
Oil and NGLs	**16.2**	20.1	(19)	**20.1**	22.3	(10)
Natural gas	**5.7**	6.2	(8)	**6.2**	9.6	(35)
Combined	**13.0**	18.0	(28)	**17.2**	19.6	(12)

The Company pays royalties to provincial governments (Crown) and other oil and gas companies that own surface or mineral rights. Crown royalties are calculated on a sliding scale based on commodity prices and individual well production rates. Royalty rates can change due to commodity price fluctuations and changes in production volumes on a well-by-well basis, subject to a minimum and maximum rate restriction ascribed by the Crown.

Royalties totaled $1.5 million and $5.2 million for the three months and year ended December 31, 2025, respectively, compared to $0.8 million and $2.7 million for the comparative periods in 2024. The increase in 2025 from 2024 was mainly as a result of the increased production and revenue at Two Rivers East. Royalty rates decreased in the three months and year ended December 31, 2025 compared to the same periods in 2024 as the result of a portion of the new oil wells at Two Rivers East being subject to British Columbia's flat 5.0% transition royalty rate for the first twelve months of equivalent production. This transition royalty program relates to oil wells drilled on or after September 1, 2024 to December 31, 2026.

OPERATING EXPENSES	**Three Months Ended December 31**			**Year Ended December 31**		
	2025	2024	% Change	**2025**	2024	% Change
Operating expenses ($000s)	**2,759**	786	251	**7,031**	3,335	111
Operating expenses ($/boe)	**7.45**	7.88	(5)	**8.26**	9.47	(13)

Per unit operating expenses decreased to $7.45/boe and $8.26/boe for the three months and year ended December 31, 2025, respectively, from $7.88/boe and $9.47/boe in the comparative periods in 2024 as a result of increased production at Two Rivers East.

NET TRANSPORTATION EXPENSES	**Three Months Ended December 31**			**Year Ended December 31**		
($000s)	**2025**	2024	% Change	**2025**	2024	% Change
Oil and NGLs	**391**	256	53	**1,235**	448	176
Natural gas	**597**	244	145	**1,552**	974	59
Net transportation expenses (non-GAAP)	**988**	500	98	**2,787**	1,422	96
Unutilized transportation	**132**	387	(66)	**831**	1,891	(56)
Transportation expenses	**1,120**	887	26	**3,618**	3,313	9
Average transportation expenses						
Oil and NGLs ($/bbl)	**3.24**	5.54	(42)	**3.79**	3.46	10
Natural gas ($/mcf)	**0.40**	0.76	(47)	**0.49**	0.73	(33)
Net transportation expenses ($/boe)	**2.67**	5.01	(47)	**3.28**	4.04	(19)
Unutilized transportation ($/boe)	**0.36**	3.88	(91)	**0.98**	5.37	(82)
Transportation expenses ($/boe)	**3.03**	8.89	(66)	**4.26**	9.41	(55)

Net transportation expenses (see "Non-GAAP and Other Financial Measures") are mainly third-party pipeline tariffs from firm transportation agreements to deliver production to the purchasers at main hubs.

Transportation expenses increased to $1.1 million and $3.6 million for the three months and year ended December 31, 2025, respectively, compared to $0.9 million and $3.3 million for the comparative periods in 2024 mainly as the result of increased production and transportation commitments.

Net transportation expenses for oil and NGLs decreased on a per unit basis to $3.24/bbl for the three months ended December 31, 2025 compared to $5.54/bbl for the comparative period in 2024 as a result of test production from new oil wells at Two Rivers East in Q4 2024 that had limited options at the time for oil terminal receipt points resulting in higher trucking costs. Net transportation expenses for oil and NGLs were comparable for the year ended December 31, 2025 relative to the comparative period in 2024.

Net transportation expenses for natural gas decreased on a per unit basis to $0.40/mcf and $0.49/mcf for the three months and year ended December 31, 2025, respectively, compared to $0.76/mcf and $0.73/mcf for the comparative periods in 2024 as a result of increased natural gas production from new wells at Two Rivers East being delivered to Westcoast Station 2 at lower transportation rates. Natural gas production exceeding the Company's 1.5 mmcf/d commitment to deliver to Chicago is being delivered to Westcoast Station 2.

Unutilized transportation is the portion of firm transportation agreements that the Company has committed to (less what has been assigned to other producers) that exceeds what the Company actually transported through pipelines for its produced natural gas volumes. See the "Contractual Obligations" section for more information related to firm transportation agreements. The Company actively manages its firm transportation commitments and has been successful in mitigating a portion of its 75.0 mmcf/d commitment to deliver natural gas to Westcoast Station 2. The Company has mitigated and reduced its Westcoast Station 2 commitment to approximately 40.6 mmcf/d through March 31, 2026 and to approximately 45.0 mmcf/d from April 1, 2026 to December 31, 2026.

OPERATING NETBACK	Three Months Ended December 31			Year Ended December 31		
($000s)	**2025**	2024	% Change	**2025**	2024	% Change
Oil and natural gas sales	**11,603**	4,544	155	**30,469**	13,736	122
Royalties	**(1,511)**	(820)	84	**(5,236)**	(2,698)	94
Operating expenses	**(2,759)**	(786)	251	**(7,031)**	(3,335)	111
Net transportation expenses (non-GAAP)	**(988)**	(500)	98	**(2,787)**	(1,422)	96
Operating netback (non-GAAP)	**6,345**	2,438	160	**15,415**	6,281	145
Depletion and depreciation	**(3,504)**	(1,073)	227	**(8,985)**	(4,786)	88
General and administrative expenses	**(2,226)**	(1,540)	45	**(6,615)**	(5,049)	31
Share based compensation	**(884)**	(706)	25	**(4,434)**	(3,917)	13
Loss on lease termination	**-**	(201)	(100)	**-**	(201)	(100)
Finance expense	**(1,821)**	(1,797)	1	**(5,837)**	(2,230)	162
Finance income	**41**	363	(89)	**261**	2,896	(91)
Unutilized transportation	**(132)**	(387)	(66)	**(831)**	(1,891)	(56)
Net loss	**(2,181)**	(2,903)	(25)	**(11,026)**	(8,897)	24

	Three Months Ended December 31			Year Ended December 31		
($/boe)	**2025**	2024	% Change	**2025**	2024	% Change
Oil and natural gas sales	**31.32**	45.57	(31)	**35.82**	39.01	(8)
Royalties	**(4.08)**	(8.22)	(50)	**(6.15)**	(7.66)	(20)
Operating expenses	**(7.45)**	(7.88)	(5)	**(8.26)**	(9.47)	(13)
Net transportation expenses (non-GAAP)	**(2.67)**	(5.01)	(47)	**(3.28)**	(4.04)	(19)
Operating netback (non-GAAP)	**17.12**	24.46	(30)	**18.13**	17.84	2
Depletion and depreciation	**(9.46)**	(10.76)	(12)	**(10.56)**	(13.59)	(22)
General and administrative expenses	**(6.01)**	(15.46)	(61)	**(7.78)**	(14.34)	(46)
Share based compensation	**(2.39)**	(7.08)	(66)	**(5.21)**	(11.12)	(53)
Loss on lease termination	**-**	(2.02)	(100)	**-**	(0.57)	(100)
Finance expense	**(4.91)**	(18.02)	(73)	**(6.86)**	(6.33)	8
Finance income	**0.11**	3.65	(97)	**0.31**	8.23	(96)
Unutilized transportation	**(0.36)**	(3.88)	(91)	**(0.98)**	(5.37)	(82)
Net loss	**(5.90)**	(29.11)	(80)	**(12.95)**	(25.25)	(49)

During the three months and year ended December 31, 2025, Coelacanth generated an operating netback (see "Non-GAAP and Other Financial Measures") of $17.12/boe and $18.13/boe, respectively, compared to $24.46/boe and $17.84/boe for the comparative periods in 2024. The decrease for the three months ended December 31, 2025 compared to 2024 was mainly the result of lower oil and NGLs pricing which was partially offset by stronger natural gas pricing and lower royalties, operating costs and net transportation costs discussed above. This decrease in oil and NGLs pricing was less prominent during the year ended December 31, 2025 than it was in the fourth quarter of 2025, and as a result, the operating netback for the year ended December 31, 2025 was consistent with the same period in 2024.

DEPLETION AND DEPRECIATION	Three Months Ended December 31			Year Ended December 31		
	2025	2024	% Change	**2025**	2024	% Change
Depletion and depreciation ($000s)	**3,504**	1,073	227	**8,985**	4,786	88
Depletion and depreciation ($/boe)	**9.46**	10.76	(12)	**10.56**	13.59	(22)

The Company calculates depletion on development and production assets included in property, plant, and equipment ("PP&E") based on proved and probable oil and natural gas reserves. Certain facility and pipeline assets included within PP&E are being depreciated on a straight-line basis over their estimated useful lives of 30 years. Depletion and depreciation expense for the three months and year ended December 31, 2025 increased to $3.5 million and $9.0 million, respectively, from $1.1 million and $4.8 million for the comparative periods in 2024 as a result of increased production and cost base of PP&E. The Company commenced depleting and depreciating the Two Rivers East development project costs in June 2025 upon the transfer from exploration and evaluation assets to PP&E. On a per boe basis, depletion and depreciation for the three months and year ended December 31, 2025 decreased to $9.46/boe and $10.56/boe, respectively, from $10.76/boe and $13.59/boe for the comparative periods in 2024 as a result of increased proved and probable reserves.

Included in depletion and depreciation expense for the three months and year ended December 31, 2025, is $30 thousand (December 31, 2024 - $50 thousand) and $0.1 million (December 31, 2024 - $0.4 million), respectively, related to the Company's right-of-use assets.

IMPAIRMENT OF PROPERTY, PLANT, AND EQUIPMENT AND EXPLORATION AND EVALUATION ASSETS

In June 2025, as a result of all wells being capable of production due to the completion of the new battery facility, the Company transferred its Two Rivers East development project costs from exploration and evaluation assets to PP&E. The Company completed the mandatory impairment test upon transfer and no impairment was recorded.

At December 31, 2025 and December 31, 2024, the Company evaluated its PP&E Two Rivers CGU for indicators of impairment or impairment reversal and as a result of this assessment management determined that an impairment test was not required to be performed.

At December 31, 2025 and December 31, 2024, the Company evaluated its exploration and evaluation assets and determined that there were no facts or circumstances suggesting that the carrying amount of its exploration and evaluation assets exceeded their recoverable amount, therefore, an impairment test was not required to be performed.

GENERAL AND ADMINISTRATIVE	**Three Months Ended December 31**			**Year Ended December 31**		
($000s)	**2025**	2024	% Change	**2025**	2024	% Change
G&A expenses (gross)	**2,626**	2,160	22	**7,244**	5,964	21
G&A capitalized	**(400)**	(620)	(35)	**(629)**	(915)	(31)
G&A expenses (net)	**2,226**	1,540	45	**6,615**	5,049	31
G&A expenses ($/boe)	**6.01**	15.46	(61)	**7.78**	14.34	(46)

Net general and administrative ("G&A") expenses increased to $2.2 million and $6.6 million for the three months and year ended December 31, 2025, respectively, from $1.5 million and $5.0 million for the comparative periods in 2024 mainly due to higher employment costs and capital management fees.

On a per unit basis G&A was $6.01/boe and $7.78/boe for the three months and year ended December 31, 2025, respectively, compared to $15.46/boe and $14.34/boe for the comparative periods in 2024. Although G&A expenses increased in 2025 compared to 2024, on a per unit basis G&A expenses decreased in 2025 from 2024 due to the increased production from the initiation of commercial production at Two Rivers East.

SHARE BASED COMPENSATION	**Three Months Ended December 31**			**Year Ended December 31**		
($000s)	**2025**	2024	% Change	**2025**	2024	% Change
Share based compensation (gross)	**1,249**	816	53	**5,319**	4,695	13
Share based compensation (capitalized)	**(365)**	(110)	232	**(885)**	(778)	14
Share based compensation (net)	**884**	706	25	**4,434**	3,917	13
Share based compensation ($/boe)	**2.39**	7.08	(66)	**5.21**	11.12	(53)

The Company accounts for its share based compensation plans using the fair value method. Under this method, compensation cost is charged to earnings over the vesting period for stock options and restricted share units ("RSUs") granted to officers, directors, employees, and consultants with a corresponding increase to contributed surplus.

Share based compensation expense totaled $0.9 million and $4.4 million for the three months and year ended December 31, 2025, respectively, consistent with $0.7 million and $3.9 million for the comparative periods in 2024. On a per unit basis share based compensation expenses decreased in 2025 from 2024 due to the increased production from the initiation of commercial production at Two Rivers East.

FINANCE EXPENSE	**Three Months Ended December 31**			**Year Ended December 31**		
($000s)	**2025**	2024	% Change	**2025**	2024	% Change
Interest expense on credit facility	**890**	371	140	**2,706**	533	408
Other obligations interest expense	**603**	9	6,600	**1,443**	77	1,774
Financing obligation payable	**-**	1,350	(100)	**-**	1,350	(100)
Amortization of financing costs	**251**	-	100	**786**	-	100
Accretion of other obligations	**-**	-	-	**614**	-	100
Accretion of decommissioning obligations	**77**	67	15	**288**	270	7
Finance expense	**1,821**	1,797	1	**5,837**	2,230	162
Finance expense ($/boe)	**4.91**	18.02	(73)	**6.86**	6.33	8

Accretion expense on decommissioning obligations was consistent for the three months and year ended December 31, 2025 compared to the same periods in 2024. Interest expense relates to interest expense and standby fees on the credit facilities and outstanding letters of guarantee for firm transportation agreements and decommissioning obligations. The large increase for the year ended December 31, 2025 from the comparable period in 2024 stems from moving from a positive cash balance at December 31, 2024 to being drawn $58.8 million on the Company's credit facilities at December 31, 2025 as a result of capital expenditures during the past twelve months. The increase in interest on other obligations is the result of a $22.7 million obligation to a midstream company funding the extension of their gathering system to connect to the Company's Two Rivers East project. Commencing June 2025, the Company is required to repay the principal amount over a five-year period at an interest rate of 12.0%. Financing obligation payable relates to non-refundable third party fees to secure the initial one-year term of the previous $45.0 million credit facility.

FINANCE INCOME

Finance income relates to interest earned on cash in the bank. Finance income totaled $41 thousand and $0.3 million for the three months and year ended December 31, 2025, respectively, compared to $0.4 million and $2.9 million for the comparative periods in 2024. The decrease corresponds to the decrease in the Company's cash balance over the comparative periods mainly due to capital expenditures during the past twelve months.

DEFERRED INCOME TAXES

The Company has not realized the net deferred income tax asset due to a history of losses and it is not probable that future taxable profits, based on the estimated cash flows derived from the independently evaluated reserve report, would be sufficient to realize the deferred income tax asset at this time.

Estimated tax pools at December 31, 2025 total approximately $325.9 million (December 31, 2024 - $264.9 million).

CASH FLOW FROM OPERATING ACTIVITIES AND ADJUSTED FUNDS FLOW

The following is a reconciliation of cash flow from operating activities to adjusted funds flow for the periods noted:

	Three Months Ended December 31			**Year Ended December 31**		
($000s)	**2025**	2024	% Change	**2025**	2024	% Change
Cash flow from operating activities	**4,852**	3,157	54	**8,906**	2,203	304
Add (deduct):						
Decommissioning expenditures	**36**	161	(78)	**421**	1,427	(70)
Change in restricted cash deposits	**(4,900)**	(5,361)	(9)	**(4,900)**	(2,376)	106
Change in non-cash working capital	**2,322**	2,425	(4)	**(1,584)**	261	(707)
Adjusted funds flow (non-GAAP)	**2,310**	382	505	**2,843**	1,515	88

Adjusted funds flow (see "Non-GAAP and Other Financial Measures") was $2.3 million ($nil per basic and diluted share) and $2.8 million ($0.01 per basic and diluted share) for the three months and year ended December 31, 2025, respectively, compared to $0.4 million ($nil per basic and diluted share) and $1.5 million ($nil per basic and diluted share) for the comparative periods in 2024. The increase for the three months and year ended December 31, 2025 was the result of increased production partially offset by increased interest expense, lower interest income and payments on the financing obligation. This is the result of the significant upfront capital costs associated with the Two Rivers East development project which commenced production in June 2025.

Cash flow from operating activities for the three months and year ended December 31, 2025 was $4.9 million ($0.01 per basic and diluted share) and $8.9 million ($0.02 per basic and diluted share), respectively, compared to $3.2 million ($0.01 per basic and diluted share) and $2.2 million ($nil per basic and diluted share) for the comparative periods in 2024. Cash flow from operating activities differs from adjusted funds flow due to the inclusion of changes in non-cash working capital, movements in restricted cash deposits and expenditures on decommissioning obligations.

NET LOSS

The Company incurred net losses of $2.2 million ($nil per basic and diluted share) and $11.0 million ($0.02 per basic and diluted share) for the three months and year ended December 31, 2025, respectively, compared to $2.9 million ($0.01 per basic and diluted share) and $8.9 million ($0.02 per basic and diluted share) for the comparative periods in 2024. The increase in 2025 compared to 2024 was mainly the result of increased depletion and depreciation resulting from increased production and cost base of PP&E partially offset by increased adjusted funds flow.

CAPITAL EXPENDITURES	**Three Months Ended December 31**			**Year Ended December 31**		
($000s)	**2025**	2024	% Change	**2025**	2024	% Change
Land	**307**	220	40	**2,743**	765	259
Drilling, completions, and workovers	**30,142**	29,273	3	**30,975**	38,353	(19)
Equipment	**3,945**	35,152	(89)	**46,633**	44,935	4
Geological and geophysical	**142**	307	(54)	**263**	444	(41)
Total expenditures	**34,536**	64,952	(47)	**80,614**	84,497	(5)

During the year ended December 31, 2025, the Company continued with facility procurement at Two Rivers East. Commercial production from Two Rivers East commenced with the completion of the facility in June 2025. In Q4 2025, the Company drilled and completed three Lower Montney wells expected to be on-stream late in Q1 2026.

During the year ended December 31, 2024, the Company continued with facility procurement at Two Rivers East and related gathering and transport pipelines. The Company drilled and completed three Lower Montney wells and completed a previously drilled Basal Montney well at Two Rivers East on the existing 5-19 pad. The Company also negotiated a reduction in royalties on certain lands in return for a royalty on additional lands.

LIQUIDITY AND CAPITAL RESOURCES

Management uses adjusted working capital deficiency and net debt (see "Non-GAAP and Other Financial Measures") as measures to assess the Company's financial position and is reconciled as follows:

($000s)	**December 31, 2025**	December 31, 2024	% Change
Current assets	**6,119**	11,579	(47)
Less:			
Current liabilities	**(48,635)**	(37,234)	31
Working capital deficiency	**(42,516)**	(25,655)	66
Add:			
Restricted cash deposits	**-**	4,900	(100)
Current portion of other obligations	**4,037**	110	3,570
Current portion of decommissioning obligations	**545**	2,118	(74)
Adjusted working capital deficiency (Capital management measure)	**(37,934)**	(18,527)	105
Credit facility, non-current	**(38,101)**	-	100
Net debt (Capital management measure)	**(76,035)**	(18,527)	310

To facilitate its capital expenditure program, the Company has an $80.0 million credit facility (refer to the "Liquidity and Capital Resources" section). At December 31, 2025, the Company had an adjusted working capital deficiency of $37.9 million which includes $19.9 million drawn under its credit facility and net debt of $76.0 million which includes $58.8 million drawn under its credit facility.

Exit 2025 production was 5,100 boe/d and exit Q1 2026 production was 8,000 boe/d with the ramp up of new wells on production on its 5-19 pad at Two Rivers East. This increase in production will help in reducing the adjusted working capital deficiency and net debt in 2026.

On November 18, 2025, the Company entered into an $80.0 million credit facility with a Canadian chartered bank to replace its previous credit facilities and returned the letter of credit to the third party. The new credit facility consists of a $10.0 million operating facility, a $50.0 million syndicated facility, and a $20.0 million term facility. The operating and syndicated facilities revolve for a 364 day period and will be subject to their next 364 day extension by May 31, 2026. If not extended, the credit facility will cease to revolve, the margins thereunder will increase by 0.50%, and all outstanding advances will become repayable in one year from the extension date (May 31, 2027). The term facility matures on May 31, 2026 and has been presented as a current liability on the statement of financial position.

Advances under the credit facility are available by way of prime rate loans, with interest rates between 2.00% and 4.00% over the Canadian prime lending rate and Canadian Overnight Repo Rate Average ("CORRA") loans which are subject to margins ranging from 3.00% to 5.00% depending upon the debt to EBITDA ratio of the Company as defined in the agreement. Standby fees are charged on the undrawn portion of the credit facility at rates ranging from 0.75% to 1.25%. Until delivery of the Q1 2026 compliance certificate, the prime rate margin is fixed at 3.0%, the CORRA margin is fixed at 4.0% and standby fees are fixed at 1.0%. The term facility margins are based on the applicable margins for the operating and syndicated facilities plus 2.5% and must be drawn first before the operating and syndicated facilities. The credit facility is secured by a $250.0 million fixed and floating charge debenture on the assets of the Company.

The credit facility includes a covenant requiring the Company to maintain an adjusted working capital ratio of not less than one-to-one. The adjusted working capital ratio, as defined in the agreement, is calculated as current assets plus any undrawn amounts available on the credit facility less current liabilities excluding amounts drawn on the credit facility. The definition of current assets and current liabilities excludes the fair value of risk management contracts and amounts associated with the pipeline obligation. The Company was compliant with this covenant at December 31, 2025.

Subsequent to December 31, 2025, the $20.0 million term facility was cancelled and replaced by an increase in the syndicated facility from $50.0 million to $80.0 million. The aggregate amended credit facility totals $90.0 million and will be subject to its next 364 day extension by May 31, 2027. If not extended, the credit facility will cease to revolve, the margins thereunder will increase by 0.50%, and all outstanding advances will become repayable in one year from the extension date (May 31, 2028). The adjusted working capital ratio covenant was also removed under the terms of the amended agreement. The next scheduled borrowing base review of the credit facility is scheduled on or before November 30, 2026.

On November 18, 2025, the Company entered into a standby letter of credit facility agreement with a third party of up to $10.0 million USD ($13.7 million CDN) to guarantee letters of credit issued by the Company to other third parties. The fee on drawn amounts under the facility are 2.82%. This facility returned $4.9 million of restricted cash deposits to the Company. At December 31, 2025, the Company has $10.1 million of standby letters of credit used against this facility (December 31, 2024 - $nil). Subsequent to December 31, 2025, an additional $1.7 million letters of credit were issued bringing the total to $11.8 million.

During the year ended December 31, 2025, the Company received $22.7 million from a midstream company to finance a pipeline connecting Coelacanth facilities to the midstream company's gathering system. Commencing June 2025, this amount will be repaid over a five-year period at an interest rate of 12.0%.

CONTRACTUAL OBLIGATIONS

The following is a summary of the Company's contractual obligations and commitments at December 31, 2025:

($000s)	Total	Less than One Year	One to Three Years	After Three Years
Accounts payable and accrued liabilities	24,278	24,278	-	-
Credit facility - principal	58,846	20,000	38,846	-
Other obligations - principal	21,949	4,037	9,543	8,369
Decommissioning obligations	9,595	545	479	8,571
Operating commitments	1,613	252	594	767
Firm transportation agreements	174,493	5,856	17,718	150,919
Firm processing agreements	122,602	10,192	23,999	88,411
Total contractual obligations	413,376	65,160	91,179	257,037

Operating commitments include the non-lease variable components (operating expenses) of the head office lease inclusive of the extension to July 31, 2031.

Transportation commitments include contracts to transport natural gas and NGLs through third-party owned pipeline systems. The Company currently has the following firm transportation commitments:

- 1.5 mmcf/d to deliver natural gas to the Alliance Trading Pool (ATP) through October 31, 2035 and then to Chicago through October 31, 2027.
- 10.0 mmcf/d to deliver natural gas to Westcoast Station 2 from January 1, 2023 through July 31, 2038.
- 50.0 mmcf/d to deliver natural gas to Westcoast Station 2 from June 1, 2023 through May 31, 2038.
- 15.0 mmcf/d to deliver natural gas to Westcoast Station 2 from May 1, 2024 through April 30, 2055.
- 25.0 mmcf/d to deliver natural gas to Westcoast Station 2 from August 1, 2028 through July 31, 2043.

The Company assigned the following contracts to third parties, thus reducing its commitment:

- 4.4 mmcf/d to deliver natural gas to Westcoast Station 2 from April 1, 2023 through March 31, 2026.
- 10.0 mmcf/d to deliver natural gas to Westcoast Station 2 from June 1, 2023 through December 31, 2027.
- 20.0 mmcf/d to deliver natural gas to Westcoast Station 2 from October 1, 2023 through October 31, 2026.

The impact of the reduced commitments are reflected in the table above.

Subsequent to December 31, 2025, the assignment of the contract for 20.0 mmcf/d to deliver natural gas to Westcoast Station 2 from October 1, 2023 through October 31, 2026 was extended with the third party for an additional year to October 31, 2027. This is expected to reduce the Company's transportation commitments by approximately $2.2 million.

Firm processing agreements include 30.0 mmcf/d of processing services at a gas processing facility for a period of 10 years. Effective July 1, 2026, the commitment increases to 40.0 mmcf/d for the remaining term. Under the terms of the processing agreement, the Company can elect prior to November 1, 2026 to increase by any volume up to an additional 20.0 mmcf/d (60.0 mmcf/d total) for the remainder of the original term. As part of the arrangement, the midstream company funded the extension of their gathering system to connect to the Company's Two Rivers East project. During the year ended December 31, 2025, the Company received $22.7 million from the midstream company. Commencing June 2025, the Company is required to repay the principal amount over a five-year period at an interest rate of 12.0%.

OFF BALANCE SHEET ARRANGEMENTS

The Company has certain lease arrangements, all of which are reflected in the contractual obligations and commitments table, which were entered into in the normal course of operations. All leases other than the fixed payment component of the head office lease and a field equipment vehicle lease have been treated as operating leases whereby the lease payments are included in operating expenses or general and administrative expenses depending on the nature of the lease.

RELATED PARTY TRANSACTIONS

For the year ended December 31, 2025, related party transactions included key management compensation. Refer to note 13 of the audited financial statements for further details.

OUTSTANDING SHARE DATA

The Company is authorized to issue an unlimited number of voting common shares, an unlimited number of non-voting common shares, Class A preferred shares, issuable in series, Class B preferred shares, issuable in series, and Class C preferred shares, issuable in series. The voting common shares of the Company commenced trading on the TSXV on June 20, 2022 under the symbol "CEI". The following table summarizes the common shares outstanding and the number of shares exercisable into common shares from options, warrants, and other instruments:

(000s)	**December 31, 2025**	April 21, 2026
Voting common shares	**533,465**	536,104
Warrants	**29,377**	29,377
Stock options	**21,587**	30,171
Restricted share units	**6,348**	9,054
Total	**590,777**	604,706

Subsequent to December 31, 2025, the Company granted 8.6 million stock options with an exercise price of $0.80 per common share expiring five years from the date of grant and vest one-third on each of the first, second and third anniversaries of the date of grant. The Company also granted 5.4 million RSUs vesting one-third on each of the first, second and third anniversaries of the date of grant.

SUMMARY OF QUARTERLY RESULTS

	Q4 2025	Q3 2025	Q2 2025	Q1 2025	Q4 2024	Q3 2024	Q2 2024	Q1 2024
Average Daily Production								
Oil and NGLs (bbls/d)	**1,316**	1,464	566	209	502	254	323	337
Natural gas (mcf/d)	**16,268**	10,896	3,861	3,311	3,490	3,450	3,724	3,934
Oil equivalent (boe/d)	**4,027**	3,280	1,210	761	1,084	829	944	993
($000s, except per share amounts)								
Oil and natural gas sales	**11,603**	11,372	4,828	2,666	4,544	2,362	3,164	3,666
Cash flow from (used in)								
operating activities	**4,852**	4,712	(1,826)	1,168	3,157	(3,730)	(480)	3,256
Per share basic and diluted (2)	**0.01**	0.01	(-)	-	0.01	(0.01)	(-)	0.01
Adjusted funds flow (used) (1)	**2,310**	2,386	(600)	(1,253)	382	(207)	262	1,078
Per share basic and diluted	**-**	-	(-)	(-)	-	(-)	-	-
Net loss	**(2,181)**	(1,764)	(3,464)	(3,617)	(2,903)	(2,464)	(2,329)	(1,201)
Per share basic and diluted	**(-)**	(-)	(0.01)	(0.01)	(0.01)	(-)	(-)	(-)

(1) Adjusted funds flow (used) and adjusted funds flow (used) per share do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. Please refer to the "Non-GAAP and Other Financial Measures" section for more details and the "Cash Flow From Operating Activities and Adjusted Funds Flow" section for a reconciliation from cash flow from operating activities.

(2) Supplemental financial measure. Please refer to the "Non-GAAP and Other Financial Measures" section for more details.

The increase in production, oil and natural gas sales, cash flow from operating activities, and adjusted funds flow in the last six months of 2025 was the result of the initiation of commercial production at Two Rivers East.

The increase in production, oil and natural gas sales, cash flow from operating activities, and adjusted funds flow in Q4 2024 stems from the testing of new wells at Two Rivers East during Q4 2024. The decrease in Q1 2025 production from Q4 2024 was natural declines and the lack of testing new wells in Q1 2025. The decrease in cash flow from operations and adjusted funds flow and the increase in net loss in the first half of 2025 was mainly the result of increased interest expense, lower interest income, and payments on financing obligation. Oil and natural gas sales, cash flow from (used in) operating activities and adjusted funds flow (used) generally followed the same trend as production with some exceptions based on volatility of commodity prices received.

MATERIAL ACCOUNTING POLICIES

All accounting policies are consistent with those of the previous financial year. Refer to note 3 of the audited financial statements for the year ended December 31, 2025 for the Company's material accounting policies.

FUTURE ACCOUNTING PRONOUNCEMENTS

IFRS 18 *Presentation and Disclosure in Financial Statements* was issued by the IASB in April 2024. IFRS 18 introduces defined categories for income and expenses and certain defined subtotals in the statement of operations and comprehensive income (loss), required disclosures of certain management-defined performance measures, and aggregation and disaggregation principles for the grouping of information in the financial statements. IFRS 18 will replace IAS 1 and is effective for annual periods beginning on or after January 1, 2027. The standard requires retrospective application with early adoption permitted. The Company is currently evaluating the impact of adopting IFRS 18 on the financial statements.

In May 2024, the IASB issued amendments to IFRS 9 *Financial Instruments* and IFRS 7 *Financial Instruments: Disclosures* regarding the settlement of financial liabilities via electronic payment systems and the assessment of contractual cash flow characteristics of financial assets. The amendments are effective for annual periods beginning on or after January 1, 2026, and require retrospective application with early adoption permitted. The Company is currently evaluating the impact of adoption on its financial statements.

CRITICAL ACCOUNTING ESTIMATES

Management is required to make estimates, judgments, and assumptions in the application of IFRS that affect the reported amounts of assets and liabilities at the date of the financial statements and revenues and expenses for the period then ended. Certain of these estimates may change from period to period resulting in a material impact on the Company's results from operations and financial position (see note 2d in the notes to the Company's December 31, 2025 financial statements for full descriptions of the use of estimates and judgments).

RISK ASSESSMENT

The acquisition, exploration, and development of oil and natural gas properties involves many risks common to all participants in the oil and natural gas industry. Coelacanth's exploration and development activities are subject to various business risks such as unstable commodity prices, interest rate and foreign exchange rate fluctuations, the uncertainty of replacing production and reserves on an economic basis, government regulations including implementation of new, or expansion of existing, tariffs on exported and/or imported products, taxes, and safety and environmental concerns. While management realizes these risks cannot be eliminated, they are committed to monitoring and mitigating these risks.

Reserves and reserve replacement

The recovery and reserve estimates on Coelacanth's properties are estimates only and the actual reserves may be materially different from that estimated. The estimates of reserve values are based on a number of variables including: forecasted oil and natural gas commodity prices, forecasted production, forecasted operating costs, forecasted royalty costs and forecasted future development costs. All of these factors may cause estimates to vary from actual results.

Coelacanth's future oil and natural gas reserves, production, and adjusted funds flow to be derived therefrom are highly dependent on the Company successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves the Company may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Coelacanth's reserves will depend on its ability to acquire suitable prospects or properties and discover new reserves.

To mitigate this risk, Coelacanth has assembled a team of experienced technical professionals who have expertise operating and exploring in areas the Company has identified as being the most prospective for increasing reserves on an economic basis. To further mitigate reserve replacement risk, Coelacanth has targeted a majority of its prospects in areas which have multi-zone potential, year-round access, and lower drilling costs and employs advanced geological and geophysical techniques to increase the likelihood of finding additional reserves.

Operational risks

Coelacanth's operations are subject to the risks normally incidental to the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells. Continuing production from a property, and to some extent the marketing of production therefrom, are largely dependent upon the ability of the operator of the property.

Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk is comprised of foreign exchange risk, interest rate risk, and other price risk, such as commodity price risk. The objective of market risk management is to manage and control market price exposures within acceptable limits, while maximizing returns. The Company may use financial derivatives or physical delivery sales contracts to manage market risks. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors.

Foreign exchange risk
The prices received by the Company for the production of oil, natural gas, and NGLs are primarily determined in reference to US dollars, but are settled with the Company in Canadian dollars. The Company's cash flow from commodity sales will therefore be impacted by fluctuations in foreign exchange rates. The Company currently does not have any foreign exchange contracts in place.

Interest rate risk
The Company is exposed to interest rate risk on its cash and credit facility balances. The Company currently does not use interest rate hedges or fixed interest rate contracts to manage the Company's exposure to interest rate fluctuations. The amount drawn on the Company's credit facilities at December 31, 2025 was $58.8 million (December 31, 2024 - $nil). A 100 basis point increase or decrease in interest rates would have impacted net loss by approximately $0.4 million for the year ended December 31, 2025 (December 31, 2024 - $nil).

Commodity price risk
Oil and natural gas prices are impacted by not only the relationship between the Canadian and US dollar but also by world economic events that dictate the levels of supply and demand. The Company's oil, natural gas, and NGLs production is marketed and sold on the spot market to area aggregators based on daily spot prices that are adjusted for product quality and transportation costs. The Company's cash flow from product sales will therefore be impacted by fluctuations in commodity prices. In addition, the Company may enter into commodity price contracts to manage future cash flows.

At December 31, 2025, the Company had the following commodity price contracts outstanding:

Commodity	Period	Type of Contract	Quantity	Contract Price
Oil	January 1, 2026 - April 30, 2026	Physical Sales	500 bbls/d	WTI CDN $86.86/bbl
Natural Gas	January 1, 2026 - March 31, 2026	Physical Sales	10,000 GJ/d	Westcoast Station 2 CDN $2.49/GJ

Subsequent to December 31, 2025, the Company entered into the following commodity price contracts:

Commodity	Period	Type of Contract	Quantity	Contract Price
Oil	May 1, 2026 - June 30, 2026	Physical Sales	500 bbls/d	WTI CDN $85.69/bbl

Credit risk

Credit risk represents the financial loss that the Company would suffer if the Company's counterparties to a financial asset fail to meet or discharge their obligation to the Company. A substantial portion of the Company's accounts receivable are with customers and joint interest partners in the oil and natural gas industry and are subject to normal industry credit risks. The Company generally grants unsecured credit but routinely assesses the financial strength of its customers and joint interest partners.

The Company sells the majority of its production to three oil and natural gas marketers and therefore is subject to concentration risk. Historically, the Company has not experienced any collection issues with its oil and natural gas marketers. Joint interest receivables are typically collected within one to three months of the joint interest billing being issued to the partner. The Company attempts to mitigate the risk from joint interest receivables by obtaining partner approval for significant capital expenditures prior to the expenditure being incurred. The Company does not typically obtain collateral from oil and natural gas marketers or joint interest partners; however, in certain circumstances, the Company may cash call a partner in advance of expenditures being incurred.

The maximum exposure to credit risk is represented by the carrying amount of cash, restricted cash deposits and accounts receivable on the statement of financial position. At December 31, 2025, $5.6 million (>99%) of the Company's outstanding accounts receivable were current and $17 thousand (<1%) were outstanding for more than 90 days. During the year ended December 31, 2025, the Company deemed $55 thousand of outstanding accounts receivable to be uncollectable (December 31, 2024 - $35 thousand).

Cash and restricted cash deposits consist of bank balances placed with a financial institution with strong investment grade ratings which management believes the risk of loss to be remote. The Company manages the credit risk exposure related to risk management contracts by selecting investment grade financial institution counterparties and by not entering into contracts for trading or speculative purposes.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's processes for managing liquidity risk includes ensuring, to the extent possible, that it will have sufficient liquidity to meet its liabilities when they become due. The Company prepares annual, quarterly, and monthly capital expenditure budgets, which are monitored and updated as required, and requires authorizations for expenditures on projects to assist with the management of capital.

To facilitate its capital expenditure program, the Company has an $80.0 million credit facility (refer to the "Liquidity and Capital Resources" section). At December 31, 2025, the Company had an adjusted working capital deficiency of $37.9 million, which includes $19.9 million drawn under its credit facility, and net debt of $76.0 million which includes $58.8 million drawn under its credit facility.

Subsequent to December 31, 2025, the $20.0 million term facility was cancelled and replaced by an increase in the syndicated facility from $50.0 million to $80.0 million. The aggregate amended credit facility totals $90.0 million and will be subject to its next 364 day extension by May 31, 2027. If not extended, the credit facility will cease to revolve, the margins thereunder will increase by 0.50%, and all outstanding advances will become repayable in one year from the extension date (May 31, 2028). The adjusted working capital ratio covenant was also removed under the terms of the amended agreement. The next scheduled borrowing base review of the credit facility is scheduled on or before November 30, 2026.

With the completion of the Two Rivers East development project, the resultant production from the 5-19 pad, and the expanded credit facility, the Company anticipates that it will have sufficient lending capacity and operational cash flows to meet its current and future obligations, to make any scheduled credit facility and associated interest payments, and to fund the other needs of the business for at least the next 12 months. Coelacanth's capital program is flexible and can be adjusted as needed based upon the current economic environment. The Company will continue to monitor the economic environment and the possible impact on its business and strategy and will make adjustments as necessary.

During the year ended December 31, 2025, the Company received $22.7 million from a midstream company to finance a pipeline connecting Coelacanth facilities to the midstream company's gathering system. Commencing June 2025, this amount will be repaid over a five-year period at an interest rate of 12.0%.

Safety and Environmental Risks

The oil and natural gas business is subject to extensive regulation pursuant to various municipal, provincial, national, and international conventions and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases, or emissions of various substances produced in association with oil and natural gas operations. Coelacanth is committed to meeting and exceeding its environmental and safety responsibilities. Coelacanth has implemented an environmental and safety policy that is designed, at a minimum, to comply with current governmental regulations set for the oil and natural gas industry. Changes to governmental regulations are monitored to ensure compliance. Environmental reviews are completed as part of the due diligence process when evaluating acquisitions. Environmental and safety updates are presented and discussed at each Board of Directors meeting. Coelacanth maintains adequate insurance commensurate with industry standards to cover reasonable risks and potential liabilities associated with its activities as well as insurance coverage for officers and directors executing their corporate duties. To the knowledge of management, there are no legal proceedings to which Coelacanth is a party or of which any of its property is the subject matter, nor are any such proceedings known to Coelacanth to be contemplated.

Geopolitical Risks

Existing or future conflicts in major oil and gas producing nations and the international response may have potential wide-ranging consequences for global market volatility and economic conditions, including affecting oil and natural gas prices. Financial and trade sanctions that may be imposed against countries involved in such conflicts may have continued far-reaching effects on the global economy, energy and commodity prices. The implications of any such conflicts is difficult to predict with any degree of certainty. Depending on the extent, duration, and severity of such conflicts, it may have the effect of heightening many of the other risks described herein, including, without limitation, risks relating to global market volatility and economic conditions; cybersecurity threats; oil and natural gas prices; inflationary pressures, interest rates and costs of capital; change in trade relations and policies, including the potential for tariffs; and supply chains and cost-effective and timely transportation.

For additional information on the risks relating to the Company's business, see the "Risk Factors" section contained in the Company's annual information form for the year ended December 31, 2025, which is available on the SEDAR+ website at www.sedarplus.com.

PRODUCT TYPES

The Company uses the following references to sales volumes in the MD&A:

Natural gas refers to shale gas
Oil and condensate refers to condensate and tight oil combined
Other NGLs refers to butane, propane and ethane combined
Oil and NGLs refers to tight oil and NGLs combined
Oil equivalent refers to the total oil equivalent of shale gas, tight oil, and NGLs combined, using the conversion rate of six thousand cubic feet of shale gas to one barrel of oil equivalent as described above.

The following is a complete breakdown of sales volumes for applicable periods by specific product types of shale gas, tight oil, and NGLs:

Sales Volumes by Product Type	**Q4 2025**	Q3 2025	Q2 2025	Q1 2025	Q4 2024	Q3 2024	Q2 2024	Q1 2024
Condensate (bbls/d)	**109**	46	17	18	**22**	33	56	19
Other NGLs (bbls/d)	**165**	92	27	25	**29**	33	39	37
NGLs (bbls/d)	**274**	138	44	43	51	66	95	56
Tight oil (bbls/d)	**1,042**	1,326	522	166	**451**	188	228	281
Condensate (bbls/d)	**109**	46	17	18	**22**	33	56	19
Oil and condensate (bbls/d)	**1,151**	1,372	539	184	473	221	284	300
Other NGLs (bbls/d)	**165**	92	27	25	**29**	33	39	37
Oil and NGLs (bbls/d)	**1,316**	1,464	566	209	502	254	323	337
Shale gas (mcf/d)	**16,268**	10,896	3,861	3,311	**3,490**	3,450	3,724	3,934
Natural gas (mcf/d)	**16,268**	10,896	3,861	3,311	3,490	3,450	3,724	3,934
Oil equivalent (boe/d)	**4,027**	3,280	1,210	761	1,084	829	944	993

FORWARD-LOOKING INFORMATION

This document contains forward-looking statements and forward-looking information within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "may", "will", "should", "believe", "intends", "forecast", "plans", "guidance" and similar expressions are intended to identify forward-looking statements or information.

More particularly and without limitation, this MD&A contains forward-looking statements and information relating to the Company's oil and condensate, other NGLs, and natural gas production, royalty rates, capital programs and expenditure plans for 2026 and 2027; drilling plans, including the anticipated drilling of a 5 or 6 well development pad in the summer of 2026; the timing of wells being placed on production, including the expectation that additional wells will be placed on production by the end of April 2026; anticipated delineation activities and resource potential; the anticipated closing of the $80.0 million equity raise on or around May 6, 2026; the Company's business plan, including expectations regarding year-over-year production growth; adjusted working capital; and the Company's expectations regarding future reserve bookings. The forward-looking statements and information are based on certain key expectations and assumptions made by the Company, including expectations and assumptions relating to prevailing commodity prices and exchange rates, applicable royalty rates and tax laws, future well production rates, the performance of existing wells, the success of drilling new wells, the availability of capital to undertake planned activities, and the availability and cost of labour and services. Specific assumptions underlying the forward-looking statements in this news release include: that the equity raise will close on the terms and timeline currently contemplated; that the Company will continue to have access to capital under its $90.0 million credit facility; that the summer 2026 drilling program will proceed on the currently anticipated timeline; that well performance will be consistent with results from existing wells at Two Rivers East; that commodity prices will remain at levels that support the Company's development plans; that there will be no material delays in regulatory approvals or permitting; and that the Company's delineation program will confirm the existence of commercial hydrocarbon quantities across the Montney zones.

Although the Company believes that the expectations reflected in such forward-looking statements and information are reasonable, it can give no assurance that such expectations will prove to be correct. Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results may differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, the risks associated with the oil and gas industry in general such as operational risks in development, exploration and production, delays or changes in plans with respect to exploration or development projects or capital expenditures, the uncertainty of estimates and projections relating to production rates, costs, and expenses, commodity price and exchange rate fluctuations, marketing and transportation, environmental risks, competition, the ability to access sufficient capital from internal and external sources and changes in tax, royalty, and environmental legislation. Additional material risks specific to the forward-looking statements in this news release include: the risk that the equity raise may not close on the anticipated terms or timeline, which could affect the Company's ability to execute its capital program; the risk that well performance may vary materially from expectations, which could affect production targets; the risk that delineation drilling may not confirm the Company's expectations regarding resource potential in the Montney zones; the risk that infrastructure capacity constraints may delay bringing new wells on production; and the risk that the Company may not be able to access capital under its credit facility on the anticipated terms. All statements regarding timing, including anticipated closing dates, production commencement dates, and drilling schedules, are estimates only and are subject to change based on operational, regulatory, and market conditions. Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions, or expectations upon which they are based will occur. The forward-looking statements and information contained in this document are made as of the date hereof for the purpose of providing the readers with the Company's expectations for the coming year. The forward-looking statements and information may not be appropriate for other purposes. The Company undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

ADDITIONAL INFORMATION

In addition to the information disclosed in this MD&A, more detailed information related to the Company can be found on the SEDAR+ website at www.sedarplus.com.

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INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Coelacanth Energy Inc.

Opinion

We have audited the financial statements of Coelacanth Energy Inc. (the Company), which comprise:

- the statements of financial position as at December 31, 2025 and December 31, 2024
- the statements of operations and comprehensive loss for the years then ended
- the statements of shareholders' equity for the years then ended
- the statements of cash flows for the years then ended
- and notes to the financial statements, including a summary of material accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2025 and December 31, 2024, and its financial performance and its cash flows for the years then ended in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the ***"Auditor's Responsibilities for the Audit of the Financial Statements"*** section of our auditor's report.

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Key Audit Matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the financial statements for the year ended December 31, 2025. These matters were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

We have determined the matter described below to be the key audit matter to be communicated in our auditor's report.

Assessment of the impact of estimated proved and probable oil and natural gas reserves on property, plant, and equipment ("PP&E")

Description of the matter

We draw attention to notes 2, 3 and 5 to the financial statements. The Company uses estimated proved and probable oil and natural gas reserves to deplete its development and production assets included in PP&E, to assess for indicators of impairment or impairment reversal on its cash-generating unit ("CGU") and, if any such indicators exist, to perform an impairment test to estimate the recoverable amount of the CGU. The Company depletes its net carrying value of development and production assets using the unit of production method by reference to the ratio of production in the period to the related proved and probable oil and natural gas reserves, taking into account estimated forecasted future development costs necessary to bring those reserves into production. At December 31, 2025, the Company had $241.6 million of PP&E and recorded $7.5 million of related depletion expense for the year.

The Company assesses at each reporting date whether there is an indication that PP&E within the Company's CGU may be impaired or that historical impairment may be reversed. The estimate of proved and probable oil and natural gas reserves is significant to the Company's assessment. The Company determined that there were no external or internal indicators of impairment or impairment reversal at December 31, 2025 for the Company's CGU and no impairment test was required.

The estimate of proved and probable oil and natural gas reserves requires the expertise of independent third party reserve evaluators and includes significant assumptions related to:

- Forecasted oil and natural gas commodity prices
- Forecasted production
- Forecasted operating costs
- Forecasted royalty costs
- Forecasted future development costs.

The Company engages independent third party reserve evaluators to estimate the proved and probable oil and natural gas reserves.

Why the matter is a key audit matter

We identified the assessment of the impact of estimated proved and probable oil and natural gas reserves on PP&E as a key audit matter. Significant auditor judgment was required to evaluate the results of our audit procedures regarding the estimate of proved and probable oil and natural gas reserves and the external and internal indicators of impairment or impairment reversal included in the Company's indicator assessment.

How the matter was addressed in the audit

The following are the primary procedures we performed to address this key audit matter:

With respect to the estimate of proved and probable oil and natural gas reserves:

- We evaluated the competence, capabilities and objectivity of the independent third party reserve evaluators engaged by the Company
- We compared forecasted oil and natural gas commodity prices to those published by other independent third party reserve evaluators
- We compared the 2025 actual production, operating costs, royalty costs and development costs of the Company to those estimates used in the prior year's estimate of proved oil and natural gas reserves to assess the Company's ability to accurately forecast
- We evaluated the appropriateness of forecasted production and forecasted operating costs, royalty costs and future development costs assumptions by comparing to 2025 historical results. We took into account changes in conditions and events affecting the Company to assess the adjustments or lack of adjustments made by the Company in arriving at the assumptions.

We assessed the depletion expense calculation for compliance with the relevant accounting standards.

We evaluated the Company's assessment of external and internal indicators of impairment or impairment reversal by considering whether the quantitative and qualitative information in the analysis was consistent with external market and industry data and the estimate of proved and probable oil and natural gas reserves.

Other Information

Management is responsible for the other information. Other information comprises:

- the information included in Management's Discussion and Analysis.
- the information, other than the financial statements and the auditor's report thereon, included in the document entitled "2025 Annual Report".

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit and remain alert for indications that the other information appears to be materially misstated.

We obtained the information included in Management's Discussion and Analysis and the information, other than the financial statements and the auditor's report thereon, included in the document entitled "2025 Annual Report" as at the date of this auditor's report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditor's report.

We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

- Provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

- Determine, from the matters communicated with those charged with governance, those matters that were of most significance in the audit of the financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our auditor's report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

KPMG LLP

Chartered Professional Accountants

The engagement partner on the audit resulting in this auditor's report is Jason Grodziski.

Calgary, Canada

April 21, 2026

Coelacanth Energy Inc.
Statements of Financial Position

($000s)	Note	**December 31 2025**	December 31 2024
Assets			
Current assets			
Cash		**-**	5,693
Accounts receivable		**5,645**	4,730
Prepaid expenses and deposits		**474**	1,156
		6,119	11,579
Restricted cash deposits	(4)	**-**	4,900
Property, plant, and equipment	(5)	**241,632**	42,381
Exploration and evaluation assets	(6)	**28,049**	154,178
		269,681	201,459
		275,800	213,038
Liabilities			
Current liabilities			
Credit facility	(8)	**19,775**	-
Accounts payable and accrued liabilities		**24,278**	33,768
Current portion of other obligations	(7)	**4,037**	110
Financing obligation payable	(8)	**-**	1,238
Current portion of decommissioning obligations	(9)	**545**	2,118
		48,635	37,234
Credit facility	(8)	**38,101**	
Other obligations	(7)	**17,912**	244
Decommissioning obligations	(9)	**9,050**	7,531
		113,698	45,009
Shareholders' Equity			
Shareholders' capital	(10)	**177,319**	175,307
Warrants	(10)	**5,015**	6,979
Contributed surplus		**12,188**	7,137
Deficit		**(32,420)**	(21,394)
		162,102	168,029
		275,800	213,038
Commitments	(22)		
Subsequent events	(8,11,17,22)		

The accompanying notes are an integral part of these financial statements.

Approved on behalf of the Board of Directors

Rob Zakresky
Director

Tom Medvedic
Director

Coelacanth Energy Inc.
Statements of Operations and Comprehensive Loss

($000s, except per share amounts)	Note	Years Ended December 31 2025	2024
Revenue			
Oil and natural gas sales	(21)	**30,469**	13,736
Royalties		**(5,236)**	(2,698)
		25,233	11,038
Expenses			
Operating		**7,031**	3,335
Transportation		**3,618**	3,313
Depletion and depreciation	(5,6)	**8,985**	4,786
General and administrative		**6,615**	5,049
Share based compensation	(11)	**4,434**	3,917
Loss on lease termination	(7)	**-**	201
Finance income		**(261)**	(2,896)
Finance expense	(14)	**5,837**	2,230
		36,259	19,935
Net loss and comprehensive loss		**(11,026)**	(8,897)
Net loss per share			
Basic and diluted	(12)	**(0.02)**	(0.02)

The accompanying notes are an integral part of these financial statements.

Coelacanth Energy Inc.
Statements of Shareholders' Equity

($000s)	**Note**	**Share-holders' Capital**	**Warrants**	**Contributed Surplus**	**Deficit**	**Total Equity**
Balance, December 31, 2023		173,918	6,562	4,119	(12,080)	172,519
Net loss		-	-	-	(8,897)	(8,897)
Settlement of vested RSUs	(10)	1,389	-	(1,389)	-	-
Settlement of stock options and RSUs	(11)	-	-	(288)	-	(288)
Share based compensation	(11)	-	-	4,695	-	4,695
Warrant extension	(10)	-	417	-	(417)	-
Balance, December 31, 2024		175,307	6,979	7,137	(21,394)	168,029
Net loss		**-**	**-**	**-**	**(11,026)**	**(11,026)**
Settlement of vested RSUs	(10)	**2,012**	**-**	**(2,012)**	**-**	**-**
Settlement of stock options	(11)	**-**	**-**	**(220)**	**-**	**(220)**
Expiry of warrants	(10)	**-**	**(1,964)**	**1,964**	**-**	**-**
Share based compensation	(11)	**-**	**-**	**5,319**	**-**	**5,319**
Balance, December 31, 2025		**177,319**	**5,015**	**12,188**	**(32,420)**	**162,102**

The accompanying notes are an integral part of these financial statements.

Coelacanth Energy Inc.
Statements of Cash Flows

($000s)	Note	Years Ended December 31 2025	2024
Operating Activities			
Net loss		**(11,026)**	(8,897)
Depletion and depreciation	(5,6)	**8,985**	4,786
Share based compensation	(11)	**4,434**	3,917
Finance expense	(14)	**5,837**	2,230
Interest paid	(14)	**(4,149)**	(610)
Financing obligation payments	(8)	**(1,238)**	(112)
Loss on lease termination	(7)	**-**	201
Decommissioning expenditures	(9)	**(421)**	(1,427)
Change in restricted cash deposits	(4)	**4,900**	2,376
Change in non-cash working capital	(20)	**1,584**	(261)
		8,906	2,203
Financing Activities			
Credit facility	(8)	**58,846**	-
Debt issue costs	(8)	**(1,060)**	-
Proceeds from other obligations, net	(7)	**22,658**	-
Payment of other obligations	(7)	**(2,206)**	(616)
Settlement of stock options and RSUs	(11)	**(220)**	(288)
Change in non-cash working capital	(20)	**311**	(969)
		78,329	(1,873)
Investing Activities			
Capital expenditures - property, plant, and equipment	(5)	**(35,891)**	(1,206)
Capital expenditures - exploration and evaluation assets	(6)	**(44,723)**	(83,291)
Change in non-cash working capital	(20)	**(12,314)**	7,292
		(92,928)	(77,205)
Change in cash		**(5,693)**	(76,875)
Cash, beginning of year		**5,693**	82,568
Cash, end of year		**-**	5,693

The accompanying notes are an integral part of these financial statements.

1. REPORTING ENTITY

Coelacanth Energy Inc. ("Coelacanth" or the "Company") is an oil and natural gas company, actively engaged in the acquisition, development, exploration, and production of oil and natural gas reserves in northeastern British Columbia, Canada. Coelacanth was incorporated in Alberta, Canada under the Business Corporations Act (Alberta) on March 24, 2022 under the name of 2418573 Alberta Ltd., and subsequently changed its name to Coelacanth Energy Inc. on April 12, 2022. The Company commenced trading on the TSX Venture Exchange ("TSXV") on June 20, 2022 under the symbol "CEI". The Company's place of business is located at 2110, 530 - 8th Avenue SW, Calgary, Alberta, Canada, T2P 3S8.

2. BASIS OF PRESENTATION

(a) Statement of compliance

These financial statements have been prepared in accordance with IFRS Accounting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

The financial statements were authorized for issuance by the Board of Directors on April 21, 2026.

(b) Basis of measurement

These financial statements have been prepared on the historical cost basis.

(c) Functional and presentation currency

The financial statements are presented in Canadian dollars, which is the functional currency of the Company.

(d) Use of estimates and judgments

The preparation of the financial statements in conformity with IFRS as issued by the IASB requires management to make estimates and use judgment regarding the reported amounts of assets and liabilities as at the date of the financial statements and the reported amounts of revenues and expenses during the period. By their nature, estimates are subject to measurement uncertainty and changes in such estimates in future periods could require a material change in the financial statements. Accordingly, actual results may differ from the estimated amounts as future confirming events occur.

Significant estimates and judgments made by management in the preparation of these financial statements are outlined below.

Cash-generating units ("CGU")
The Company's assets are aggregated into CGUs which are determined based on the smallest group of assets that generate cash inflows independent of other assets or groups of assets. Determination of CGUs is subject to the Company's judgment and is based on geographical proximity, shared infrastructure, similar exposure to market risk, and materiality.

Impairment
Significant management judgment is required to analyze internal and external indicators of impairment or historical impairment reversal with the estimate of proved and probable oil and natural gas reserves being significant to the assessment. In determining the estimated recoverable amount of assets or CGUs, in the absence of quoted market prices, impairment tests are based on the estimate of proved and probable oil and natural gas reserves. The estimate of proved and probable oil and natural gas reserves includes significant assumptions related to: forecasted oil and natural gas commodity prices, forecasted production, forecasted operating costs, forecasted royalty costs, forecasted future development costs, discount rates and other relevant assumptions.

Exploration and evaluation assets
The application of the Company's accounting policy for exploration and evaluation ("E&E") assets requires the Company to make certain judgments as to future events and circumstances as to whether economic quantities of proved and probable oil and natural gas reserves will be found so as to assess if technical feasibility and commercial viability has been achieved.

Reserves
The Company uses estimated proved and probable oil and natural gas reserves to deplete its development and production assets included in property, plant, and equipment, to assess for indicators of impairment or impairment reversal on its CGU and, if any such indicators exist, to perform an impairment test to estimate the recoverable amount of the CGU. The Company's proved and probable oil and natural gas reserves represent the estimated quantities of oil, natural gas, and natural gas liquids ("NGLs") which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be economically recoverable in future years from known reservoirs and which are considered commercially producible. Proved and probable oil and natural gas reserves requires estimation and are subject to assumptions regarding: forecasted oil and natural gas commodity prices, forecasted production, forecasted operating costs, forecasted royalty costs and forecasted future development costs. Changes in reported proved and probable oil and natural gas reserves can impact the carrying values of the Company's property, plant, and equipment, E&E assets, the calculation of depletion expense, and the provision for decommissioning obligations due to changes in expected future cash flows. The estimated proved and probable oil and natural gas reserves are evaluated by independent third party reserve evaluators at least annually in accordance with the standards contained in National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* and the Canadian Oil and Gas Evaluation Handbook.

Decommissioning obligations
Amounts recorded for decommissioning obligations requires the use of estimates with respect to the amount and timing of decommissioning expenditures. Actual costs and cash outflows can differ from estimates because of changes in laws and regulations, public expectations, market conditions, discovery and analysis of site conditions and changes in technology.

Deferred taxes
Deferred taxes are based on estimates as to the timing of the reversal of temporary differences, substantively enacted tax rates, and the likelihood of assets being realized. Tax interpretations, regulations, and legislation in the various jurisdictions in which the Company operates are subject to change. As such, income taxes are subject to measurement uncertainty. Judgments are also required to determine the likelihood of whether deferred income taxes at the end of the reporting period will be realized from future taxable earnings.

Current operating and reporting environment
Numerous factors beyond the Company's control influence the marketability and pricing of oil, natural gas, and NGLs, which may experience significant volatility. These factors include uncertainties in supply and demand driven by government policies, global economic conditions, sanctions and tariffs, shifts in global trade flows, changes in foreign exchange, interest and inflation rates, actions by OPEC+, political and geopolitical instability, regulatory changes, ongoing conflicts, and other macroeconomic or political developments. Specifically, adverse changes in Canada and U.S. trade relations, particularly regarding tariffs and energy, could negatively affect the Company given the integration of North American energy markets. Given the uncertainty surrounding the magnitude, duration, and potential outcomes of these factors, the Company cannot currently predict their long-term impact on its operations, liquidity, financial condition, or results; however, the impact may be material.

Emissions, carbon and other regulations impacting climate and climate-related matters are constantly evolving. The Company considers the impact of the evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels. The ultimate period in which global energy markets can transition from carbon-based sources to alternative energy is highly uncertain and the Company will continue to monitor its estimates as the energy evolution continues. Estimates regarding the value of the Company's development and production assets, reserves and decommissioning obligations are all subject to measurement uncertainty due to the risks of government policy and climate change .

3. MATERIAL ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently by the Company to all periods presented in these financial statements.

(a) Joint arrangements

Many of the Company's oil and natural gas activities involve undivided interests in jointly owned assets and these financial statements reflect only the Company's proportionate interest in such activities. The Company has no arrangements classified as joint ventures.

(b) Financial instruments

Non-derivative financial instruments

Financial instruments are recognized initially at fair value. Measurement in subsequent periods is dependent on the financial instrument's classification. The initial classification of a financial asset into one of the following three categories depends on the Company's business model for managing its financial assets and the contractual terms of the cash flows: (i) amortized cost; (ii) fair value through other comprehensive income ("FVOCI"); or (iii) fair value through profit or loss ("FVTPL").

Financial assets designated at amortized cost are initially recognized at fair value, net of directly attributable transaction costs, and are subsequently measured at amortized cost using the effective interest method, net of any impairment.

Financial liabilities are classified and measured at amortized cost or FVTPL. Other financial liabilities are initially measured at fair value less attributable transaction costs and are subsequently measured at amortized cost using the effective interest method.

The Company's financial instruments classified and measured at amortized cost comprise cash, restricted cash deposits, accounts receivable, accounts payable and accrued liabilities, the credit facility, and the pipeline obligation. The Company has not designated any financial instruments as FVOCI or FVTPL.

Financial assets and liabilities are offset and the net amount reported in the statement of financial position when there is a legally enforceable right to offset the recognized amounts, and there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

Cash

Cash is comprised of cash held in bank accounts.

Share capital

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares are recognized as a deduction from equity, net of any tax effects.

(c) Property, plant, and equipment and exploration and evaluation assets

Recognition and measurement

Exploration and evaluation expenditures
Pre-license costs are recognized in earnings as incurred.

Exploration and evaluation costs, including the costs of acquiring undeveloped land and drilling costs, are initially capitalized until the drilling of the well is complete and the results have been evaluated. The costs are accumulated in cost centers by well, field, or exploration area pending determination of technical feasibility and commercial viability. The technical feasibility and commercial viability of extracting a mineral resource is generally considered to be determinable when proved or probable oil and natural gas reserves are determined to exist and infrastructure to support commercial development is available. Once technical feasibility and commercial viability has been established, the accumulated costs and associated undeveloped land are transferred to development and production assets included in property, plant, and equipment. The exploration and evaluation costs are reviewed for impairment prior to any such transfer.

Assets classified as E&E may have sales associated with production from test wells prior to the reclassification to property, plant, and equipment. These operating results are recognized in the statement of operations and comprehensive loss.

Exploration and evaluation assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and are transferred to property, plant, and equipment, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, exploration and evaluation assets are allocated to their respective CGUs.

Development and production costs
Items of property, plant, and equipment, which include development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. The cost of development and production assets includes: transfers from exploration and evaluation assets, which generally include the cost to drill the well and the cost of the associated land upon determination of technical feasibility and commercial viability; the cost to complete and tie-in the well; facility costs; the cost of recognizing provisions for future restoration and decommissioning obligations; geological and geophysical costs; and directly attributable overhead.

Development and production assets are grouped into CGUs for impairment testing. The Company currently has one CGU located in northeast British Columbia, being the Two Rivers CGU.

When significant parts of an item of property, plant, and equipment have different useful lives, they are accounted for as separate items (major components).

Gains and losses on disposal of an item of property, plant, and equipment are determined by comparing the proceeds from disposal with the carrying amount of property, plant, and equipment and are recognized in earnings. The carrying amount of any replaced or disposed item of property, plant, and equipment is derecognized.

Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant, and equipment are recognized as property, plant, and equipment only when they increase the future economic benefits embodied in the specific asset to which they relate. Capitalized property, plant, and equipment generally represent costs incurred in developing proved or probable oil and natural gas reserves and bringing in or enhancing production from such reserves and are accumulated on a field or area basis. The costs of the day-to-day servicing of property, plant, and equipment are recognized in operating expenses as incurred.

Non-monetary asset swaps

Exchanges or swaps of property, plant, and equipment are measured at fair value unless the exchange transaction lacks commercial substance or neither the fair value of the assets given up nor the assets received can be reliably estimated. The cost of the acquired asset is measured at the fair value of the asset given up, unless the fair value of the asset received is more clearly evident. Where fair value is not used, the cost of the acquired asset is measured at the carrying amount of the asset given up. Any gain or loss on derecognition of the asset given up is included in earnings. Exchanges or parts of exchanges that involve principally exploration and evaluation assets are measured at the carrying amount of the asset exchanged, reduced by the amount of any cash consideration received. No gain or loss is recognized unless the cash consideration received exceeds the carrying value of the asset held.

Depletion and depreciation

The Company depletes its net carrying value of development and production assets using the unit of production method by reference to the ratio of production in the period to the related proved and probable oil and natural gas reserves, taking into account estimated forecasted future development costs necessary to bring those reserves into production. Estimated salvage value of the assets at the end of their useful lives is also taken into account. The Company engages independent third party reserve evaluators to estimate the proved and probable oil and natural gas reserves. Natural gas volumes are converted to equivalent oil volumes based upon the relative energy content of six thousand cubic feet of natural gas to one barrel of oil.

Certain facility and pipeline assets included within development and production assets are being depreciated on a straight-line basis over their estimated useful lives of 30 years.

The cost of office and other equipment is depreciated using the straight-line method over the estimated useful life of between three and six years.

Depreciation methods, useful lives, and salvage values are reviewed at each reporting date and, if necessary, changes are accounted for prospectively.

(d) Leases

The Company assesses whether a contract is a lease based on whether the contract conveys the right to control the use of an underlying asset for a period of time in exchange for consideration.

The Company recognizes a right-of-use (“ROU”) asset and a lease liability at the lease commencement date. The ROU asset is initially measured at cost based on the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received. The assets are depreciated to the earlier of the end of the useful life of the ROU asset or the lease term using the straight-line method as this most closely reflects the expected pattern of consumption of the future economic benefits. The Company includes ROU assets in property, plant, and equipment on the statement of financial position. The lease term includes periods covered by an option to extend if the Company is reasonably certain to exercise that option. In addition, the ROU asset is periodically reduced by impairment losses, if any, and adjusted for certain re-measurements of the lease liability.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease or, if that rate cannot be readily determined, the Company’s incremental borrowing rate. Generally, the Company uses its incremental borrowing rate as the discount rate.

The lease liability is measured at amortized cost using the effective interest method. It is re-measured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Company’s estimate of the amount expected to be payable under a residual value guarantee, or if the Company changes its assessment of whether it will exercise a purchase, extension or termination option. When the lease liability is re-measured in this way, a corresponding adjustment is made to the carrying amount of the ROU asset, or is recorded in earnings if the carrying amount of the ROU asset has been reduced to zero. Lease payments are applied against the lease obligation, with a portion reflected as interest expense using the effective interest method. The Company includes lease liabilities in other obligations on the statement of financial position.

(e) Impairment

Financial assets

The Company has elected to measure loss allowances for its financial assets measured at amortized cost at an amount equal to lifetime expected credit losses (“ECLs”) as its accounts receivable are due within a period of less than one year and are not considered to have a significant financing component. The maximum period considered when estimating ECLs is the maximum contractual period over which the Company is exposed to credit risk. ECLs are a probability-weighted estimate of credit losses. Credit losses are measured as the present value of all cash shortfalls (i.e., the difference between the cash flows due to the Company in accordance with the contract and the cash flows that the Company expects to receive). ECLs are discounted at the effective interest rate of the financial asset.

Non-financial assets

The Company assesses at each reporting date whether there is an indication that property, plant, and equipment within the Company’s cash-generating unit may be impaired or that historical impairment may be reversed. If any such indication exists, then the cash-generating unit’s recoverable amount is estimated. Exploration and evaluation assets are assessed for impairment when they are transferred to development and production assets included in property, plant, and equipment or if facts and circumstances suggest that the carrying amount exceeds the recoverable amount. ROU assets may be tested as part of a cash-generating unit, as a separate cash-generating unit or as an individual asset.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (a cash-generating unit or “CGU”). The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs of disposal.

Fair value less costs of disposal is determined to be the amount for which the asset could be sold in an arm's length transaction between knowledgeable and willing parties. Fair value less costs of disposal is generally determined using discounted cash flows from the estimate of proved and probable oil and natural gas reserves considering recent market transactions. These calculations are corroborated by valuation multiples or other available fair value indicators.

Value in use is determined from the estimate of proved and probable oil and natural gas reserves discounted to their present value using a pre-tax discount rate that reflects the current market assessments of the time value of money and risks specific to the asset.

An impairment loss is recognized if the carrying amount of a CGU exceeds its estimated recoverable amount. Impairment losses are recognized in earnings. Impairment losses recognized in respect of CGUs are allocated to the assets in the CGUs on a pro rata basis. Impairment losses recognized in prior periods are assessed each reporting date if facts or circumstances indicate that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset’s carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

(f) Share based compensation

The Company uses the fair value method for valuing share based compensation. Under this method, the compensation cost attributed to stock options and restricted share units is measured at fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options and restricted share units that vest. Upon the settlement of the stock options and restricted share units, the previously recognized value in contributed surplus is recorded as an increase to share capital.

(g) Provisions

Provisions are recognized when the Company has a present obligation as a result of a past event that can be estimated with reasonable certainty. Provisions are measured by estimating the cash flows that the Company would pay to be relieved of the obligation. To the extent that provisions are estimated using a present value technique, such amounts are determined by discounting the estimated future cash flows at a risk-free pre-tax rate. Provisions are not recognized for future operating losses.

Decommissioning obligations
The Company's activities give rise to dismantling, decommissioning, and site disturbance remediation activities. A provision is made for the estimated cost of abandonment and site restoration and capitalized in the relevant asset category. The capitalized amount is depreciated on a unit of production basis over the life of the associated proved and probable oil and natural gas reserves. Decommissioning obligations are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the reporting date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time, changes in the estimated future cash flows underlying the obligation, and changes in the risk-free rate. The increase in the provision due to the passage of time is recognized as accretion (within finance expenses) whereas increases or decreases due to changes in the estimated future cash flows or changes in the discount rate are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

(h) Revenue

The Company earns revenue from its production and sale of oil, natural gas and NGLs.

Revenue from the sale of oil, natural gas and NGLs is recognized based on the consideration specified in contracts with customers. The Company recognizes revenue when control of the product transfers to the customer and collection is reasonably assured. This is generally at the point in time when the customer obtains legal title to the product which is when it is physically transferred to the pipeline or other transportation method agreed upon.

The Company evaluates its arrangements with third parties and partners to determine if the Company is acting as the principal or as an agent. In making this evaluation, management considers if the Company obtains control of the product delivered, which is indicated by the Company having the primary responsibility for the delivery of the product, having the ability to establish prices or having inventory risk. If the Company acts in the capacity of an agent rather than as a principal in a transaction, then revenue is recognized on a net basis, only reflecting the fee, if any, realized by the Company from the transaction.

Tariffs, tolls and fees charged to other entities for use of pipelines and facilities owned by the Company are evaluated by management to determine if these originate from contracts with customers or from incidental or collaborative arrangements. Tariffs, tolls and fees charged to other entities that are from contracts with customers are recognized in revenue when the related services are provided.

When allocating the transaction price realized in contracts with multiple performance obligations (sale of commodities and sale of transportation services), management is required to make estimates of the prices at which the Company would sell the product or service separately to customers.

(i) Finance income and expenses

Finance income and expense comprises interest expense on credit facilities, interest expense on lease and pipeline obligations, costs associated with credit facility commitment and origination fees, accretion on decommissioning, lease and pipeline obligations, and interest income earned on cash in the bank.

(j) Income tax

Income tax expense is comprised of current and deferred tax. Income tax expense is recognized in earnings except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized on the temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis, or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable earnings will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(k) Per share amounts

Basic per share amounts are calculated by dividing the net earnings or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted per share amounts are determined by adjusting the weighted average number of common shares outstanding during the period for the effects of dilutive instruments such as stock options and restricted share units granted using the treasury stock method.

(l) New accounting standards and future accounting pronouncements

IFRS 18 *Presentation and Disclosure in Financial Statements* was issued by the IASB in April 2024. IFRS 18 introduces defined categories for income and expenses and certain defined subtotals in the statement of operations and comprehensive income (loss), required disclosures of certain management-defined performance measures, and aggregation and disaggregation principles for the grouping of information in the financial statements. IFRS 18 will replace IAS 1 and is effective for annual periods beginning on or after January 1, 2027. The standard requires retrospective application with early adoption permitted. The Company is currently evaluating the impact of adopting IFRS 18 on the financial statements.

In May 2024, the IASB issued amendments to IFRS 9 *Financial Instruments* and IFRS 7 *Financial Instruments: Disclosures* regarding the settlement of financial liabilities via electronic payment systems and the assessment of contractual cash flow characteristics of financial assets. The amendments are effective for annual periods beginning on or after January 1, 2026, and require retrospective application with early adoption permitted. The Company is currently evaluating the impact of adoption on its financial statements.

4. RESTRICTED CASH DEPOSITS

The Company has $nil in restricted guaranteed investment certificates ("GIC's") with a Canadian chartered bank (December 31, 2024 - $4.9 million). These restricted GIC's were being held as security for $4.9 million of letters of guarantee to third parties relating to firm transportation agreements. During the year ended December 31, 2025, the restricted cash deposits were released (see note 8).

	December 31, 2025	December 31, 2024
Current	**-**	-
Long-term	**-**	4,900
	-	4,900

5. PROPERTY, PLANT, AND EQUIPMENT

Cost	**Total**
Balance, December 31, 2023	94,783
Additions	1,206
Derecognition of right-of-use asset (note 7)	(1,038)
Capitalized share based compensation	111
Change in decommissioning obligation estimates (note 9)	551
Balance, December 31, 2024	95,613
Additions	**35,891**
Transfer from exploration and evaluation assets (note 6)	**171,732**
Capitalized share based compensation	**393**
Change in decommissioning obligation estimates (note 9)	**(309)**
Right-of-use asset additions (note 7)	**529**
Balance, December 31, 2025	**303,849**

Accumulated Depletion, Depreciation, and Impairment	**Total**
Balance, December 31, 2023	49,072
Derecognition of right-of-use asset (note 7)	(577)
Depletion and depreciation	4,737
Balance, December 31, 2024	53,232
Depletion and depreciation	**8,985**
Balance, December 31, 2025	**62,217**

Net Book Value	**Total**
December 31, 2024	42,381
December 31, 2025	**241,632**

During the year ended December 31, 2025, approximately $0.4 million (December 31, 2024 - $36 thousand) of directly attributable general and administrative costs were capitalized as expenditures on property, plant, and equipment (“PP&E”).

Depletion and depreciation

In June 2025, as a result of all wells being capable of production due to completion of the new battery facility, the Company transferred $170.0 million of its Two Rivers East development project costs from exploration and evaluation assets to PP&E. The $170.0 million consisted of $86.0 million of facility and infrastructure costs, $81.0 million of well costs, and $3.0 million of land costs.

The calculation of depletion and depreciation expense for the year ended December 31, 2025 included an estimated $113.8 million (December 31, 2024 - $21.4 million) for forecasted future development costs associated with proved and probable undeveloped oil and natural gas reserves and excluded approximately $7.0 million (December 31, 2024 - $1.0 million) for the estimated salvage value of production equipment and facilities. Depletion expense on development and production assets was $7.5 million for the year ended December 31, 2025 (December 31, 2024 - $4.3 million). At December 31, 2025, $7.2 million of assets under construction were excluded from the depreciation calculation (December 31, 2024 - $nil).

Included in depletion and depreciation expense for the year ended December 31, 2025, is $0.1 million (December 31, 2024 - $0.4 million) related to the Company’s right-of-use assets. At December 31, 2025, the net book value of the right-of-use assets is $0.7 million (December 31, 2024 - $0.3 million).

Impairment assessment

The Company determined that there were no external or internal indicators of impairment or impairment reversal at December 31, 2025 and December 31, 2024 for its PP&E Two Rivers CGU and no impairment test was required to be performed.

6. EXPLORATION AND EVALUATION ASSETS

	Total
Balance, December 31, 2023	68,883
Additions	83,291
Change in decommissioning obligation estimates (note 9)	1,386
Capitalized share based compensation	667
Lease expiries	(49)
Balance, December 31, 2024	154,178
Additions	**44,723**
Transfer to property, plant, and equipment (note 5)	**(171,732)**
Change in decommissioning obligation estimates (note 9)	**388**
Capitalized share based compensation	**492**
Balance, December 31, 2025	**28,049**

Exploration and evaluation (“E&E”) assets consist of the Company’s exploration projects which are pending the determination of proved or probable oil and natural gas reserves and an assessment of technical feasibility and commercial viability. Additions represent the Company’s share of costs incurred on exploration and evaluation assets during the period, consisting primarily of undeveloped land, drilling costs, and facility costs until the drilling of the well is complete and the results have been evaluated.

In June 2025, the Company’s Two Rivers East development project commenced production. The Company completed an impairment test on transfer of assets from E&E assets to PP&E and no impairment was recorded. Included in the $170.0 million of costs transferred were costs associated with multi-well pad drilling and completion, undeveloped land, and pipeline and facility construction.

During the year ended December 31, 2025, approximately $0.3 million (December 31, 2024 - $0.9 million) of directly attributable general and administrative costs were capitalized as expenditures on E&E assets.

During the year ended December 31, 2025, $nil (December 31, 2024 - $49 thousand) of land lease expiries have been included in depletion and depreciation expense.

At December 31, 2025 and December 31, 2024, the Company evaluated its E&E assets and determined that there were no facts or circumstances suggesting that the carrying amount of its E&E assets exceeded their recoverable amount, therefore, an impairment test was not required to be performed.

7. OTHER OBLIGATIONS

	Pipeline obligation	Lease obligations	Total
Balance, December 31, 2023	-	1,230	1,230
Termination	-	(260)	(260)
Lease payments	-	(693)	(693)
Interest expense (note 14)	-	77	77
Balance, December 31, 2024	-	354	354
Additions	**22,700**	**52**	**22,752**
Transaction costs	**(42)**	**-**	**(42)**
Modification	**-**	**477**	**477**
Payments	**(3,521)**	**(128)**	**(3,649)**
Interest expense (note 14)	**1,402**	**41**	**1,443**
Accretion (note 14)	**614**	**-**	**614**
Balance, December 31, 2025	**21,153**	**796**	**21,949**
Current	**3,955**	**82**	**4,037**
Long-term	**17,198**	**714**	**17,912**
	21,153	**796**	**21,949**

Pipeline obligation
During the year ended December 31, 2025, the Company received $22.7 million from a midstream company for the transfer of the extension of its gathering system (a pipeline) to connect the Company's Two Rivers East project to the midstream company's processing facility. The Company legally transferred the pipeline to the midstream company, however, the transfer did not result in a loss of control for accounting purposes. Accordingly, Coelacanth continues to account for the asset within PP&E and has recognized on inception a financial liability of $22.7 million, reflecting the obligation to make payments over a five-year term. The obligation is discounted with an effective interest rate of 11.5% with payments commencing on the in-service date of the Company's Two Rivers East facility in June 2025.

Lease obligations

The Company has the following leases in place as at December 31, 2025:

- On August 1, 2025, the Company entered into a supplementary lease and lease extension on its current head office premises. The lease obligation is discounted with an effective interest rate of 9.5% and the right-of-use asset is amortized based on the lease term. The modified lease expires July 31, 2031 with a renewal option of an additional five-year term. Only the first term of the lease has been recognized as a right-of-use asset and lease obligation as the Company is not reasonably certain it will exercise the renewal option. The Company’s office lease originally expired on November 30, 2027, in which the lease obligations were discounted with an effective interest rate of 5.5%. The right-of-use asset related to the office lease has been modified to include the extension.

- Field equipment vehicle lease commencing December 5, 2025 and expiring November 5, 2028. The lease obligation is discounted with an effective interest rate of 8.5% and the right-of-use asset is amortized based on the lease term.

The total undiscounted amount of the estimated future cash flows to settle the lease obligation over the remaining term is $1.0 million. The Company’s minimum lease payments are as follows:

	December 31, 2025
Within one year	154
Later than one year but not later than three years	359
Later than three years	533
Minimum lease payments	1,046
Amount representing interest expense	(250)
Present value of net lease obligation payments	**796**

During the year ended December 31, 2024, the Company terminated a field equipment lease. The early termination of the lease for a lump sum payment of $0.2 million resulted in a loss on termination of $0.2 million.

The expense recognized relating to short-term leases and leases of low-value assets for year ended December 31, 2025 was $71 thousand (December 31, 2024 - $3 thousand) and has been included in operating expenses and general and administrative expenses.

For the year ended December 31, 2025, $0.2 million (December 31, 2024 - $0.2 million) of non-lease variable expenses relating to the head office lease have been included within general and administrative expenses.

8. CREDIT FACILITY

	Total
Balance, December 31, 2023 and 2024	-
Net proceeds	**58,846**
Issuance costs	**(1,060)**
Amortization of issuance costs	**90**
Balance, December 31, 2025	**57,876**
Current	**19,775**
Long-term	**38,101**
	57,876

On November 18, 2025, the Company entered into an $80.0 million credit facility with a Canadian chartered bank to replace its previous credit facilities and returned the letter of credit to the third party. Associated with the letter of credit was a non-refundable third party letter of credit fee payable monthly until December 2025. The balance of the financing obligation payable at December 31, 2025 is $nil (December 31, 2024 - $1.2 million). The new credit facility consists of a $10.0 million operating facility, a $50.0 million syndicated facility, and a $20.0 million term facility. The operating and syndicated facilities revolve for a 364 day period and will be subject to their next 364 day extension by May 31, 2026. If not extended, the credit facility will cease to revolve, the margins thereunder will increase by 0.50%, and all outstanding advances will become repayable in one year from the extension date (May 31, 2027). The term facility matures on May 31, 2026 and has been presented as a current liability on the statement of financial position.

Advances under the credit facility are available by way of prime rate loans, with interest rates between 2.00% and 4.00% over the Canadian prime lending rate and Canadian Overnight Repo Rate Average ("CORRA") loans which are subject to margins ranging from 3.00% to 5.00% depending upon the debt to EBITDA ratio of the Company as defined in the agreement. Standby fees are charged on the undrawn portion of the credit facility at rates ranging from 0.75% to 1.25%. Until delivery of the Q1 2026 compliance certificate, the prime rate margin is fixed at 3.0%, the CORRA margin is fixed at 4.0% and standby fees are fixed at 1.0%. The term facility margins are based on the applicable margins for the operating and syndicated facilities plus 2.5% and must be drawn first before the operating and syndicated facilities. The credit facility is secured by a $250.0 million fixed and floating charge debenture on the assets of the Company.

The credit facility includes a covenant requiring the Company to maintain an adjusted working capital ratio of not less than one-to-one. The adjusted working capital ratio, as defined in the agreement, is calculated as current assets plus any undrawn amounts available on the credit facility less current liabilities excluding amounts drawn on the credit facility. The definition of current assets and current liabilities excludes the fair value of risk management contracts and amounts associated with the pipeline obligation (note 7). The Company was compliant with this covenant at December 31, 2025.

Subsequent to December 31, 2025, the $20.0 million term facility was cancelled and replaced by an increase in the syndicated facility from $50.0 million to $80.0 million. The aggregate amended credit facility totals $90.0 million and will be subject to its next 364 day extension by May 31, 2027. If not extended, the credit facility will cease to revolve, the margins thereunder will increase by 0.50%, and all outstanding advances will become repayable in one year from the extension date (May 31, 2028). The adjusted working capital ratio covenant was also removed under the terms of the amended agreement. The next scheduled borrowing base review of the credit facility is scheduled on or before November 30, 2026.

On November 18, 2025, the Company entered into a standby letter of credit facility agreement with a third party of up to $10.0 million USD ($13.7 million CDN) to guarantee letters of credit issued by the Company to other third parties. The fee on drawn amounts under the facility are 2.82%. This facility returned $4.9 million of restricted cash deposits to the Company (see note 4). At December 31, 2025, the Company has $10.1 million of standby letters of credit used against this facility (December 31, 2024 - $nil). Subsequent to December 31, 2025, an additional $1.7 million letters of credit were issued bringing the total to $11.8 million.

9. DECOMMISSIONING OBLIGATIONS

The Company's decommissioning obligations result from its ownership interest in development and production assets including well sites and gathering systems. The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to abandon and reclaim the wells and facilities, and the estimated timing of the costs to be incurred in future periods. These estimates were made by management using information obtained from government estimates and internal analysis assuming current costs, technology and enacted legislation. The total undiscounted amount of the estimated cash flows, adjusted for inflation at 1.93% per year (December 31, 2024 - 1.81%) required to settle the decommissioning obligations is approximately $18.3 million (December 31, 2024 - $16.7 million) which is estimated to be incurred over the next 32 years. At December 31, 2025, a risk-free rate of 3.80% (December 31, 2024 - 3.32%) was used to calculate the net present value of the decommissioning obligations.

	Year Ended December 31, 2025	Year Ended December 31, 2024
Balance, beginning of year	**9,649**	8,869
Provisions incurred	**675**	1,407
Provisions settled	**(421)**	(1,427)
Revisions in estimated cash flows	**(201)**	565
Revisions due to change of rates	**(395)**	(35)
Accretion (note 14)	**288**	270
Balance, end of year	**9,595**	9,649
Current	**545**	2,118
Long-term	**9,050**	7,531
	9,595	9,649

10. SHAREHOLDERS' CAPITAL AND WARRANTS

The Company is authorized to issue an unlimited number of voting common shares, an unlimited number of non-voting common shares, Class A preferred shares, issuable in series, Class B preferred shares, issuable in series, and Class C preferred shares, issuable in series. No non-voting common shares or preferred shares have been issued.

Voting Common Shares	Number	Amount
Balance, December 31, 2023	528,650	173,918
Settlement of restricted share units	2,020	1,389
Balance, December 31, 2024	530,670	175,307
Settlement of restricted share units	**2,795**	**2,012**
Balance, December 31, 2025	**533,465**	**177,319**

Warrants	Number	Amount
Balance, December 31, 2023	62,710	6,562
Extension of expiry date	-	417
Balance, December 31, 2024	62,710	6,979
Expired	**(33,333)**	**(1,964)**
Balance, December 31, 2025	**29,377**	**5,015**

The following table summarizes the warrants outstanding and exercisable at December 31, 2025:

Issue Date	Expiry Date	Exercise Price	Number
June 10, 2022	June 10, 2027	$0.27	27,502
November 16, 2023	November 16, 2028	$0.80	1,875
			29,377

During the year ended December 31, 2024, the expiry date for 33.3 million bought-deal warrants with an exercise price of $1.05 per warrant was extended from November 15, 2024 to June 30, 2025. The fair value of the extension of the expiry date for the bought-deal warrants was estimated on the date of extension using the Black-Scholes-Merton option pricing model with the following assumptions:

	November 15, 2024
Risk-free interest rate (%)	**3.2**
Expected life (years)	**0.6**
Expected volatility (%)	**38.5**
Expected dividend yield (%)	**-**
Fair value of warrants issued ($ per warrant)	**0.01**

On June 30, 2025, the 33.3 million bought-deal warrants expired unexercised.

11. SHARE BASED COMPENSATION PLANS

Stock options

The Company has authorized and reserved for issuance 53.3 million common shares under a stock option plan enabling certain officers, directors, employees, and consultants to purchase common shares. The Company will not issue options exceeding 10% of the shares outstanding at the time of the option grants (any performance share units "PSUs" or restricted share units "RSUs" described below are aggregated with any stock options for the 10% limit). Under the plan, the exercise price of each option equals the market price of the Company's shares on the date of the grant and an option's maximum term is ten years. At December 31, 2025, 21.6 million options were outstanding at an average exercise price of $0.75 per share.

	Number of Options	Weighted Average Exercise Price ($)
Balance, December 31, 2023	13,249	0.68
Granted	5,687	0.79
Settled	(745)	0.54
Forfeited	(1,220)	0.76
Balance, December 31, 2024	16,971	0.72
Granted	**5,727**	**0.81**
Settled	**(1,081)**	**0.64**
Forfeited	**(30)**	**0.61**
Balance, December 31, 2025	**21,587**	**0.75**
Exercisable, December 31, 2025	**10,214**	**0.69**

The following table summarizes the stock options outstanding and exercisable at December 31, 2025:

	Options Outstanding			Options Exercisable	
Exercise Price	**Number**	**Weighted Average Remaining Life (years)**	**Weighted Average Exercise Price**	**Number**	**Weighted Average Exercise Price**
$0.54 to $0.70	4,079	1.7	0.56	3,779	0.55
$0.71 to $0.79	4,327	2.0	0.75	3,059	0.75
$0.80 to $0.83	13,181	3.5	0.81	3,376	0.80
	21,587	2.9	0.75	10,214	0.69

The Company accounts for its share based compensation plans using the fair value method. Under this method, compensation cost is charged to earnings over the vesting period for stock options granted to officers, directors, employees, and consultants with a corresponding increase to contributed surplus. The stock options granted vest one-third on each of the first, second and third anniversaries of the date of grant.

The fair value of the stock options granted were estimated on the date of grant using the Black-Scholes-Merton option pricing model with the following weighted average assumptions:

	Year Ended December 31, 2025	Year Ended December 31, 2024
Risk-free interest rate (%)	**2.9**	3.8
Expected life (years)	**4.0**	4.0
Expected volatility (%)	**49.0**	64.6
Expected dividend yield (%)	**-**	-
Forfeiture rate (%)	**6.9**	4.7
Weighted average fair value of options granted ($ per option)	**0.33**	0.41

During the year ended December 31, 2025, the Company recognized $2.4 million (December 31, 2024 - $2.4 million) of share based compensation related to the stock options of which $2.0 million was recognized as an expense and $0.4 million was capitalized (December 31, 2024 - $2.0 million was recognized as an expense and $0.4 million was capitalized). At December 31, 2025 there was $1.2 million remaining as unrecognized share based compensation related to the stock options.

For the year ended December 31, 2025, the Company settled 1.1 million stock options for a $220 thousand cash payment (December 31, 2024 - 0.7 million stock options for a $272 thousand cash payment).

Subsequent to December 31, 2025, the Company granted 8.6 million stock options with an exercise price of $0.80 per common share expiring five years from the date of grant and vest one-third on each of the first, second and third anniversaries of the date of grant.

Restricted share units

Subject to the terms and conditions of the performance and restricted share unit plan, each RSU award entitles the holder to an award value to be settled as to one-third on each of the first, second and third anniversaries of the date of grant. For the purpose of calculating share based compensation, the fair value of each award is determined at the grant date using the closing price of the Company's common shares. On the date of exercise, the Company has the option of settling the award value in cash (payment is based on the closing price of the Company’s common shares on day prior to exercise), common shares of the Company (one common share for each RSU), or a combination thereof. It is the Company’s intention to settle the RSUs in common shares of the Company.

	Number of RSUs
Balance, December 31, 2023	5,380
Granted	2,789
Exercised	(2,020)
Settled	(21)
Forfeited	(549)
Balance, December 31, 2024	5,579
Granted	**3,564**
Exercised	**(2,795)**
Balance, December 31, 2025	**6,348**
Exercisable, December 31, 2025	**-**

The weighted average market price of the Company's common shares used to value the RSUs granted during the year ended December 31, 2025 was $0.81 (December 31, 2024 - $0.79). During the year ended December 31, 2025, the Company recognized $2.9 million (December 31, 2024 - $2.3 million) of share based compensation related to the RSUs of which $2.4 million was recognized as an expense and $0.5 million was capitalized (December 31, 2024 - $1.9 million was recognized as an expense and $0.4 million was capitalized). At December 31, 2025, there was $1.7 million remaining as unrecognized share based compensation related to the RSUs.

For the year ended December 31, 2025, the Company settled nil RSUs in cash (December 31, 2024 - 21 thousand RSUs for a $16 thousand cash payment).

Subsequent to December 31, 2025, the Company granted 5.4 million RSUs vesting one-third on each of the first, second and third anniversaries of the date of grant.

Performance share units

Subject to the terms and conditions of the performance and restricted share unit plan, each PSU award entitles the holder to an award value to be settled as to one-third on each of the first, second and third anniversaries of the date of grant multiplied by a payout multiplier ranging from 0 to 2.0 times and is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period. For the purpose of calculating share based compensation, the fair value of each award is determined at the grant date using the closing price of the Company's common shares. On the date of exercise, the Company has the option of settling the award value in cash, common shares of the Company, or a combination thereof.

To date, no PSUs have been granted under the performance and restricted share unit plan.

12. PER SHARE AMOUNTS

The following table summarizes the weighted average number of shares used in the basic and diluted net loss per share calculations:

	December 31, 2025	December 31, 2024
Weighted average number of shares - basic	**532,448**	529,804
Dilutive effect of share based compensation plans and warrants	**-**	-
Weighted average number of shares - diluted	**532,448**	529,804

For the year ended December 31, 2025, 21.6 million stock options (December 31, 2024 - 17.0 million), 6.3 million RSUs (December 31, 2024 - 5.6 million), and 29.4 million warrants (December 31, 2024 - 62.7 million), were excluded from the weighted-average share calculation because they were anti-dilutive due to the net loss.

13. KEY MANAGEMENT PERSONNEL

The Company considers its directors and executives to be key management personnel. The key management personnel compensation is comprised of the following:

	December 31, 2025	December 31, 2024
Short-term wages and benefits and severance	**2,372**	2,651
Share based compensation (1)	**3,759**	3,430
Total (2,3)	**6,131**	6,081

(1) Represents the amortization of share based compensation expense associated with the Company's share based compensation plans granted to key management personnel.
(2) Balances outstanding and payable at December 31, 2025 were $nil (December 31, 2024 - $nil).
(3) At December 31, 2025, key management personnel included 10 individuals (December 31, 2024 - 10 individuals).

14. FINANCE EXPENSE

Finance expense includes the following:

	December 31, 2025	December 31, 2024
Interest expense on credit facility (note 8)	**2,706**	533
Other obligations interest expense (note 7)	**1,443**	77
Financing obligation payable (note 8)	**-**	1,350
Amortization of financing costs (note 8)	**786**	-
Accretion of other obligations (note 7)	**614**	-
Accretion of decommissioning obligations (note 9)	**288**	270
Finance expense	**5,837**	2,230

15. INCOME TAXES

The provision for income taxes in the statements of operations and comprehensive loss reflects an effective tax rate which differs from the expected statutory tax rate. The differences were accounted for as follows:

	December 31, 2025	December 31, 2024
Loss before taxes	**11,026**	8,897
Statutory income tax rate	**25.0%**	25.0%
Expected income tax recovery	**2,757**	2,224
(Increase) decrease in income taxes resulting from:		
Share based compensation and other non-deductible amounts	**(436)**	(394)
Change in unrecognized deferred tax asset	**(2,321)**	(1,830)
Deferred income tax recovery	**-**	-

The tax rate consists of the combined federal and provincial statutory tax rates for the Company for the years ended December 31, 2025 and December 31, 2024.

Under the terms of the arrangement on May 31, 2022, involving Coelacanth, Leucrotta Exploration Inc. and Vermilion Energy Inc., the Company acquired tax pools in the approximate amount of $85.0 million. The Company may not recognize deductible temporary differences of $39.5 million at December 31, 2025 (December 31, 2024 - $45.6 million) related to the excess of tax pools acquired over the carrying value of the net assets transferred because the common control transaction is not a business combination and is therefore subject to the initial recognition exemption under IAS 12 *Income Taxes*. Deferred income tax assets and liabilities are not recognized for temporary differences arising on the initial recognition of an asset or liability in a transaction that is not a business combination and at the time of the transaction, effects neither the accounting profit nor taxable profits.

At December 31, 2025 the Company has an unrecognized net deferred income tax asset due to a history of losses and it is not probable that future taxable profits, based on the estimated cash flows derived from the independently evaluated reserve report, would be sufficient to realize the deferred income tax asset at this time.

At December 31, 2025, the Company has estimated tax pools of $325.9 million (December 31, 2024 - $264.9 million) available for deduction against future taxable income.

The components and movements in net deferred income tax assets and liabilities are as follows:

	December 31, 2024	Recognized in net loss	December 31, 2025
Deferred income tax assets (liabilities)			
PP&E and E&E assets	(23,862)	(14,261)	(38,123)
Non-capital losses	23,862	14,261	38,123
Net deferred income tax asset (liability)	-	-	-

	December 31, 2023	Recognized in net loss	December 31, 2024
Deferred income tax assets (liabilities)			
PP&E and E&E assets	(14,240)	(9,622)	(23,862)
Non-capital losses	14,240	9,622	23,862
Net deferred income tax asset (liability)	-	-	-

Unrecognized deductible temporary differences are as follows:

	December 31, 2025	December 31, 2024
PP&E and E&E assets	**39,537**	45,581
Other obligations	**21,948**	354
Restricted share units	**4,082**	3,087
Financing obligation payable	**-**	1,238
Decommissioning obligations	**9,595**	9,649
Share issue costs	**2,727**	3,139
Restricted interest and finance expenses	**5,021**	-
Non-capital losses	**9,195**	19,772
Unrecognized deductible temporary differences	**92,105**	82,820

Non-capital losses of $161.7 million will expire between 2042 and 2047.

16. FAIR VALUE OF FINANCIAL INSTRUMENTS

The fair value of cash, restricted cash deposits, accounts receivable, accounts payable and accrued liabilities, credit facility, and pipeline obligation at December 31, 2025 and December 31, 2024 approximated their carrying value.

The Company classifies the fair value of its financial instruments at fair value according to the following hierarchy based on the amount of observable inputs used to value the instrument:

- Level 1 – observable inputs, such as quoted market prices in active markets;
- Level 2 – inputs, other than the quoted market prices in active markets, which are observable, either directly or indirectly;
- Level 3 – unobservable inputs for the asset or liability in which little or no market data exists, therefore requiring an entity to develop its own assumptions.

During the years ended December 31, 2025 and December 31, 2024, there were no transfers between level 1, level 2, and level 3 classified assets and liabilities as there are no financial instruments recognized at fair value.

17. FINANCIAL RISK MANAGEMENT

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production, and financing activities. The Company employs risk management strategies and policies to ensure that any exposure to risk is in compliance with the Company's business objectives and risk tolerance levels. Risk management is ultimately established by the Board of Directors and is implemented by management.

Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk is comprised of foreign exchange risk, interest rate risk, and other price risk, such as commodity price risk. The objective of market risk management is to manage and control market price exposures within acceptable limits, while maximizing returns. The Company may use financial derivatives or physical delivery sales contracts to manage market risks. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors.

Foreign exchange risk
The prices received by the Company for the production of oil, natural gas, and NGLs are primarily determined in reference to US dollars but are settled with the Company in Canadian dollars. The Company's cash flow from commodity sales will therefore be impacted by fluctuations in foreign exchange rates. The Company does not currently have any foreign exchange contracts in place.

Interest rate risk
The Company is exposed to interest rate risk on its cash and credit facility balances. The Company currently does not use interest rate hedges or fixed interest rate contracts to manage the Company's exposure to interest rate fluctuations. The amount drawn on the Company's credit facilities at December 31, 2025 was $58.8 million (December 31, 2024 - $nil). A 100 basis point increase or decrease in interest rates would have impacted net loss by approximately $0.4 million for the year ended December 31, 2025 (December 31, 2024 - $nil).

Commodity price risk
Oil and natural gas prices are impacted by not only the relationship between the Canadian and US dollar but also by world economic events that dictate the levels of supply and demand. The Company's oil, natural gas, and NGLs production is marketed and sold on the spot market to area aggregators based on daily spot prices that are adjusted for product quality and transportation costs. The Company's cash flow from product sales will therefore be impacted by fluctuations in commodity prices. In addition, the Company may enter into commodity price contracts to manage future cash flows.

At December 31, 2025, the Company had the following commodity price contracts outstanding:

Commodity	Period	Type of Contract	Quantity	Contract Price
Oil	January 1, 2026 - April 30, 2026	Physical Sales	500 bbls/d	WTI CDN $86.86/bbl
Natural Gas	January 1, 2026 - March 31, 2026	Physical Sales	10,000 GJ/d	Westcoast Station 2 CDN $2.49/GJ

Subsequent to December 31, 2025, the Company entered into the following commodity price contracts:

Commodity	Period	Type of Contract	Quantity	Contract Price
Oil	May 1, 2026 - June 30, 2026	Physical Sales	500 bbls/d	WTI CDN $85.69/bbl

The Company accounts for any physical sales contracts as executory contracts and as such are not recorded at fair value on the statement of financial position. Settlements on these physical sales contracts are recognized in oil and natural gas sales.

Credit risk

Credit risk represents the financial loss that the Company would suffer if the Company's counterparties to a financial asset fail to meet or discharge their obligation to the Company. A substantial portion of the Company's accounts receivable are with customers and joint interest partners in the oil and natural gas industry and are subject to normal industry credit risks. The Company generally grants unsecured credit but routinely assesses the financial strength of its customers and joint interest partners.

The Company sells the majority of its production to three oil and natural gas marketers and therefore is subject to concentration risk. Historically, the Company has not experienced any collection issues with its oil and natural gas marketers. Joint interest receivables are typically collected within one to three months of the joint interest billing being issued to the partner. The Company attempts to mitigate the risk from joint interest receivables by obtaining partner approval for significant capital expenditures prior to the expenditure being incurred. The Company does not typically obtain collateral from oil and natural gas marketers or joint interest partners; however, in certain circumstances, the Company may cash call a partner in advance of expenditures being incurred.

As at December 31, 2025 and 2024, accounts receivable was comprised of the following:

	December 31, 2025	December 31, 2024
Oil and natural gas marketers	**4,245**	989
Joint interest partners	**27**	90
GST and other	**1,373**	3,651
Total accounts receivable	**5,645**	4,730

The maximum exposure to credit risk is represented by the carrying amount of cash, restricted cash deposits and accounts receivable on the statement of financial position. At December 31, 2025, $5.6 million (>99%) of the Company's outstanding accounts receivable were current and $17 thousand (<1%) were outstanding for more than 90 days. During the year ended December 31, 2025, the Company deemed $55 thousand of outstanding accounts receivable to be uncollectable (December 31, 2024 - $35 thousand).

Cash and restricted cash deposits consist of bank balances placed with a financial institution with strong investment grade ratings which management believes the risk of loss to be remote. The Company manages the credit risk exposure related to risk management contracts by selecting investment grade financial institution counterparties and by not entering into contracts for trading or speculative purposes.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's processes for managing liquidity risk includes ensuring, to the extent possible, that it will have sufficient liquidity to meet its liabilities when they become due. The Company prepares annual, quarterly, and monthly capital expenditure budgets, which are monitored and updated as required, and requires authorizations for expenditures on projects to assist with the management of capital.

To facilitate its capital expenditure program, the Company has an $80.0 million credit facility (see note 8). At December 31, 2025, the Company had an adjusted working capital deficiency of $37.9 million which includes $19.8 million drawn under its credit facility.

Subsequent to December 31, 2025, the $20.0 million term facility was cancelled and replaced by an increase in the syndicated facility from $50.0 million to $80.0 million. The aggregate amended credit facility totals $90.0 million and will be subject to its next 364 day extension by May 31, 2027. If not extended, the credit facility will cease to revolve, the margins thereunder will increase by 0.50%, and all outstanding advances will become repayable in one year from the extension date (May 31, 2028). The adjusted working capital ratio covenant was also removed under the terms of the amended agreement. The next scheduled borrowing base review of the credit facility is scheduled on or before November 30, 2026.

With the completion of the Two Rivers East development project, the resultant production from the 5-19 pad, and the expanded credit facility, the Company anticipates that it will have sufficient lending capacity and operational cash flows to meet its current and future obligations, to make any scheduled credit facility and associated interest payments, and to fund the other needs of the business for at least the next 12 months. Coelacanth's capital program is flexible and can be adjusted as needed based upon the current economic environment. The Company will continue to monitor the economic environment and the possible impact on its business and strategy and will make adjustments as necessary.

The timing of undiscounted cash outflows relating to the Company's financial liabilities at December 31, 2025 is outlined in the table below. It is not expected that the cash flows included in the maturity analysis could occur significantly earlier or at significantly different amounts, with the exception of a future breach of a covenant under the credit facility that would require repayment earlier than indicated. Interest on the credit facility has been excluded as interest payments fluctuate based on amounts outstanding and the prevailing interest rate at the time of borrowing.

	2026	2027	2028	2029	2030	Total
Accounts payable and accrued liabilities	24,278	-	-	-	-	24,278
Credit facility - principal (1)	20,000	38,846	-	-	-	58,846
Pipeline obligation	6,035	6,035	6,035	6,035	2,518	26,658
Total	**50,313**	**44,881**	**6,035**	**6,035**	**2,518**	**109,782**

(1) Subsequent to December 31, 2025, the $20.0 million term facility due May 31, 2026 was cancelled and replaced by an increase in the syndicated facility (see note 8).

See note 7 for a maturity analysis of the Company's lease obligations and note 22 for a summary of contractual commitments at December 31, 2025.

During the year ended December 31, 2025, the Company received $22.7 million from a midstream company to finance a pipeline connecting Coelacanth facilities to the midstream company's gathering system (see note 7). Commencing June 2025, this amount will be repaid over a five-year period at an interest rate of 12.0%.

18. CAPITAL MANAGEMENT

The Company's objectives when managing capital are to maintain a flexible capital structure, which optimizes the cost of capital at an acceptable risk, and to maintain investor, creditor, and market confidence to sustain future development of the business.

The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying assets. The Company considers its capital structure to include shareholders' equity , adjusted working capital deficiency, and net debt. Adjusted working capital deficiency includes current assets and restricted cash deposits less current liabilities, excluding the current portion of decommissioning obligations and other obligations. Net debt includes adjusted working capital deficiency and non-current portion of the credit facility. To maintain or adjust the capital structure, the Company may, from time to time, issue shares, raise debt, or adjust its capital spending to manage its current and projected debt levels.

	December 31, 2025	December 31, 2024
Shareholders' equity	**162,102**	168,029
Net debt	**(76,035)**	(18,527)

Management uses net debt as a measure to assess the Company's financial position and is reconciled as follows:

($000s)	**December 31, 2025**	December 31, 2024
Current assets	**6,119**	11,579
Less:		
Current liabilities	**(48,635)**	(37,234)
Working capital deficiency	**(42,516)**	(25,655)
Add:		
Restricted cash deposits	**-**	4,900
Current portion of other obligations	**4,037**	110
Current portion of decommissioning obligations	**545**	2,118
Adjusted working capital deficiency	**(37,934)**	(18,527)
Credit facility, non-current	**(38,101)**	-
Net debt	**(76,035)**	(18,527)

In addition, management prepares annual, quarterly, and monthly budgets, which are updated depending on varying factors such as general market conditions and successful capital deployment. The Company's share capital is not subject to external restrictions, however, the Company's credit facility includes a covenant requiring the Company to maintain an adjusted working capital ratio of not less than one-to-one (see note 8).

19. SUPPLEMENTAL DISCLOSURES

Presentation of expenses

The Company's statement of operations and comprehensive loss is prepared primarily by nature of expense, with the exception of employee compensation costs which are included in general and administrative expenses. Included in general and administrative expenses for the year ended December 31, 2025 are $4.3 million of wages and benefits (December 31, 2024 - $3.9 million).

20. SUPPLEMENTAL CASH FLOW INFORMATION

	December 31, 2025	December 31, 2024
Accounts receivable	**(915)**	(591)
Prepaid expenses and deposits [(1)]	**(14)**	(739)
Accounts payable and accrued liabilities	**(9,490)**	7,392
Change in non-cash working capital	**(10,419)**	6,062
Relating to:		
Operating	**1,584**	(261)
Financing	**311**	(969)
Investing	**(12,314)**	7,292
Change in non-cash working capital	**(10,419)**	6,062

(1) For the year ended December 31, 2025, excludes $0.7 million (December 31, 2024 - $nil) of debt issuance costs paid in 2024 that were re-classified as a reduction to the credit facility in 2025 when the facility was drawn on (see note 8).

21. REVENUE

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

The contracts generally have a term of one year or less, whereby delivery takes place throughout the contract period. Revenues are typically collected on the 25th day of the month following production.

The following table presents the Company's oil and natural gas revenues disaggregated by revenue source:

	December 31, 2025	December 31, 2024
Oil and condensate	**23,382**	10,465
Other NGLs	**685**	419
Natural gas	**6,402**	2,852
Total revenue	**30,469**	13,736

Under certain marketing arrangements the Company will transfer title of its natural gas production to a third-party marketing company who will subsequently redeliver the natural gas production to an end customer by utilizing the Company's pipeline capacity. This portion representing the sale of transportation services is presented within natural gas revenue which is disaggregated in the below table by type:

	December 31, 2025	December 31, 2024
Natural gas production sales	**4,883**	1,894
Transportation revenue	**1,519**	958
Natural gas sales	**6,402**	2,852

The Company's revenue was generated entirely in the province of British Columbia. The majority of revenue resulted from sales whereby the transaction price was based on index prices. Of total oil and natural gas sales, three customers represented combined sales of 95% for the year ended December 31, 2025 (December 31, 2024 - three customers represented combined sales of 86%).

22. COMMITMENTS

The following is a summary of the Company's contractual obligations and commitments at December 31, 2025:

	2026	**2027**	**2028**	**2029**	**2030**	**Thereafter**	**Total**
Operating commitments	252	297	297	297	297	173	1,613
Firm transportation agreements	5,856	7,806	9,912	11,540	11,540	127,839	174,493
Firm processing agreements	10,192	11,881	12,118	12,360	12,608	63,443	122,602
	16,300	19,984	22,327	24,197	24,445	191,455	298,708

Operating commitments include the non-lease variable components (operating expenses) of the head office lease inclusive of the extension to July 31, 2031 (see note 7).

Transportation commitments include contracts to transport natural gas and NGLs through third-party owned pipeline systems. The Company currently has the following firm transportation commitments:

- 1.5 mmcf/d to deliver natural gas to the Alliance Trading Pool (ATP) through October 31, 2035 and then to Chicago through October 31, 2027.
- 10.0 mmcf/d to deliver natural gas to Westcoast Station 2 from January 1, 2023 through July 31, 2038.
- 50.0 mmcf/d to deliver natural gas to Westcoast Station 2 from June 1, 2023 through May 31, 2038.
- 15.0 mmcf/d to deliver natural gas to Westcoast Station 2 from May 1, 2024 through April 30, 2055.
- 25.0 mmcf/d to deliver natural gas to Westcoast Station 2 from August 1, 2028 through July 31, 2043.

The Company assigned the following contracts to third parties, thus reducing its commitment:

- 4.4 mmcf/d to deliver natural gas to Westcoast Station 2 from April 1, 2023 through March 31, 2026.
- 10.0 mmcf/d to deliver natural gas to Westcoast Station 2 from June 1, 2023 through December 31, 2027.
- 20.0 mmcf/d to deliver natural gas to Westcoast Station 2 from October 1, 2023 through October 31, 2026.

The impact of the reduced commitments are reflected in the table above.

Subsequent to December 31, 2025, the assignment of the contract for 20.0 mmcf/d to deliver natural gas to Westcoast Station 2 from October 1, 2023 through October 31, 2026 was extended with the third party for an additional year to October 31, 2027. This is expected to reduce the Company's transportation commitments by approximately $2.2 million.

Firm processing agreements include 30.0 mmcf/d of processing services at a gas processing facility for a period of 10 years. Effective July 1, 2026, the commitment increases to 40.0 mmcf/d for the remaining term. Under the terms of the processing agreement, the Company can elect prior to November 1, 2026 to increase by any volume up to an additional 20.0 mmcf/d (60.0 mmcf/d total) for the remainder of the original term. As part of the arrangement, the midstream company funded the extension of their gathering system (see note 7).

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FORWARD-LOOKING STATEMENTS

This Interim Report may contain forward-looking information that involves a number of risks and uncertainties that could cause actual results to differ materially from those anticipated. For this purpose, any statements herein that are not statements of historical fact may be deemed to be forward-looking statements. Such risks and uncertainties include, but are not limited to: risks associated with the oil and gas industry (e.g. operational risks in exploration, development and production; changes and/or delays in the development of capital assets; uncertainty of reserve estimates; uncertainty of estimates and projections relating to production and costs; commodity price fluctuations; environmental risks; and industry competition).

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2025

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