Q2 2026 RESULTS

FINANCIAL AND OPERATING RESULTS FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2026

COELACANTH ENERGY INC.

HIGHLIGHTS

- Increased oil and natural gas production 531% to 7,632 boe/d in Q2 2026 from 1,210 boe/d in Q2 2025.
- Increased adjusted funds flow 1,889% to $10.7 million in Q2 2026 from adjusted funds used of $0.6 million in Q2 2025.
- Amended and restated the credit facility to extend and increase the credit facility from $80.0 million to $90.0 million.
- Closed a bought-deal public financing issuing 97.6 million common shares of the Company at a price of $0.82 per share for gross proceeds of $80.0 million.

FINANCIAL RESULTS	THREE MONTHS ENDED JUNE 30			SIX MONTHS ENDED JUNE 30		
($000s, except per share amounts)	2026	2025	% Change	2026	2025	% Change
OIL AND NATURAL GAS SALES	**23,200**	4,828	381	**45,363**	7,494	505
CASH FLOW FROM (USED IN) OPERATING ACTIVITIES	**13,808**	(1,826)	(856)	**21,566**	(658)	(3,378)
Per share - basic and diluted (1)	**0.02**	(-)	(100)	**0.04**	(-)	(100)
ADJUSTED FUNDS FLOW (USED)(2)	**10,735**	(600)	(1,889)	**21,054**	(1,853)	(1,236)
Per share - basic and diluted	**0.02**	(-)	(100)	**0.04**	(-)	100
NET INCOME (LOSS)	**3,960**	(3,464)	(214)	**7,800**	(7,081)	(210)
Per share - basic and diluted	**0.01**	(0.01)	(200)	**0.01**	(0.01)	(200)
CAPITAL EXPENDITURES (3)	**4,468**	14,273	(69)	**11,272**	39,974	(72)
ADJUSTED WORKING CAPITAL (DEFICIENCY) (4)				**6,529**	(38,035)	(117)
NET CASH (DEBT) (5)				**6,529**	(38,035)	(117)
COMMON SHARES OUTSTANDING (000s)						
Weighted average - basic	**596,166**	532,274	12	**565,827**	531,862	6
Weighted average - diluted	**620,435**	532,274	17	**590,096**	531,862	11
End of period - basic				**633,850**	532,866	19
End of period - fully diluted				**695,408**	591,544	18

(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 (used) and adjusted funds flow (used) 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 (Used in) Operating Activities and Adjusted Funds Flow (Used)" section in the MD&A for a reconciliation from cash flow from (used in) 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 cash (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 June 30			Six Months Ended June 30		
	2026	2025	% Change	**2026**	2025	% Change
Daily production [2]						
Oil and condensate (bbls/d)	**1,613**	539	199	**1,758**	362	386
Other NGLs (bbls/d)	**392**	27	1,352	**347**	26	1,235
Oil and NGLs (bbls/d)	**2,005**	566	254	**2,105**	388	443
Natural gas (mcf/d)	**33,764**	3,861	774	**29,499**	3,588	722
Oil equivalent (boe/d)	**7,632**	1,210	531	**7,022**	986	612
Oil and natural gas sales						
Oil and condensate ($/bbl)	**115.51**	82.58	40	**100.68**	84.51	19
Other NGLs ($/bbl)	**28.19**	26.96	5	**27.13**	32.19	(16)
Oil and NGLs ($/bbl)	**98.44**	79.91	23	**88.56**	81.01	9
Natural gas ($/mcf)	**1.71**	2.02	(15)	**2.17**	2.77	(22)
Oil equivalent ($/boe)	**33.41**	43.86	(24)	**35.69**	41.97	(15)
Operating netback and net income (loss) ($/boe)						
Oil and natural gas sales	**33.41**	43.86	(24)	**35.69**	41.97	(15)
Royalties	**(3.46)**	(8.26)	(58)	**(3.53)**	(7.85)	(55)
Operating expenses	**(7.43)**	(10.86)	(32)	**(7.59)**	(10.77)	(30)
Net transportation expenses [3]	**(2.59)**	(4.33)	(40)	**(2.65)**	(4.20)	(37)
Operating netback [4]	**19.93**	20.41	(2)	**21.92**	19.15	14
Depletion and depreciation	**(8.20)**	(12.76)	(36)	**(8.33)**	(13.35)	(38)
General and administrative expenses	**(2.46)**	(13.69)	(82)	**(2.64)**	(16.78)	(84)
Stock based compensation	**(1.05)**	(10.31)	(90)	**(1.54)**	(13.43)	(89)
Finance expense	**(2.33)**	(13.02)	(82)	**(3.12)**	(12.96)	(76)
Finance income	**0.04**	0.64	(94)	**0.02**	0.96	(98)
Unutilized transportation	**(0.22)**	(2.75)	(92)	**(0.17)**	(3.25)	(95)
Net income (loss)	**5.71**	(31.48)	(118)	**6.14**	(39.66)	(115)

(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 income (loss).

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

August 24, 2026

The MD&A should be read in conjunction with the unaudited condensed interim financial statements and related notes for the three and six months ended June 30, 2026 and the audited financial statements and related notes for the year ended December 31, 2025. The unaudited condensed interim 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

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 (used)
Management uses adjusted funds flow (used) 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, if any. Adjusted funds flow (used) is a non-GAAP financial measure and has been defined by the Company as cash flow from (used in) operating activities excluding the change in non-cash working capital related to operating activities 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 (used) is reconciled from cash flow from (used in) operating activities under the heading "Cash Flow from (Used in) Operating Activities and Adjusted Funds Flow (Used)".

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 June 30		Six Months Ended June 30	
($000s)	**2026**	2025	**2026**	2025
Transportation expenses	**1,949**	779	**3,582**	1,330
Unutilized transportation	**(151)**	(303)	**(215)**	(580)
Net transportation expenses (non-GAAP)	**1,798**	476	**3,367**	750

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 June 30		Six Months Ended June 30	
($000s)	**2026**	2025	**2026**	2025
Oil and natural gas sales	**23,200**	4,828	**45,363**	7,494
Royalties	**(2,404)**	(910)	**(4,491)**	(1,401)
Operating expenses	**(5,160)**	(1,195)	**(9,653)**	(1,923)
Net transportation expenses	**(1,798)**	(476)	**(3,367)**	(750)
Operating netback (non-GAAP)	**13,838**	2,247	**27,852**	3,420

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 June 30		Six Months Ended June 30	
($000s)	**2026**	2025	**2026**	2025
Capital expenditures – property, plant, and equipment	**3,827**	370	**9,923**	1,038
Capital expenditures – exploration and evaluation assets	**641**	13,903	**1,349**	38,936
Capital expenditures (non-GAAP)	**4,468**	14,273	**11,272**	39,974

Capital Management Measures

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

Non-GAAP Financial Ratios

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

In Q2 2026, Coelacanth produced an average of 7,632 boe/d with all 5-19 pad wells on production. Capital was mainly spent on upgrading water handling and construction of the 9-32 pad.

Capital operations for Q3 2026 will include drilling four wells on the 9-32 pad and completion of the 12-27 Lower Montney well at Two Rivers West. The 9-32 pad includes a 5-mile step-out in the Upper Montney following up the successful B5-19 Upper Montney well. A successful step-out at 9-32 would prove out a very material geographic area for reserve bookings as no undeveloped locations were booked to the greater area at the end of 2025. The 12-27 well was originally drilled for land retention and was logged and cored before a 3,860 metre horizontal leg was drilled in the Lower Montney. The core had indicated enhanced porosity in the Basal Montney with the Lower Montney stacked on top creating a 90 metre thick zone with similar porosity. The 12-27 well is approximately 8 miles west of the 5-19 Pad and there are no reserves booked in the Lower or Basal Montney within a large radius.

The long-term view for LNG expansion in British Columbia is very positive for Coelacanth's land. Coelacanth delivers its gas to the Westcoast pipeline that has a direct connection to Coastal GasLink and LNG Canada. We believe lands that have scale and direct access such as Coelacanth's will trade at a premium once they are delineated and the resource is proven for development. Additional LNG projects may also increase the competition for oil and gas properties as LNG owners enter the upstream market to acquire Montney resources with the vast majority already owned by large companies.

While Coelacanth's large undeveloped resource of 150 sections of Montney lands (estimated to hold 6.9 billion barrels of Discovered Oil Initially-In-Place (IIP) and 5.9 trillion cubic feet of Discovered Gas IIP plus 8.3 billion barrels of Undiscovered Oil IIP and 7.1 trillion cubic feet of Undiscovered Gas IIP) [(1)] is expected to drive long-term value, short-term conditions are not as favourable. LNG Canada is currently estimated to be producing significantly less than capacity creating a suboptimal pricing environment for gas from Westcoast that is amplified by generally weak natural gas pricing in Canada and the US.

As such, Coelacanth is taking a cautious approach from a capital perspective yet still maintaining maximum delineation of the resource. Wells for 2027 will focus mainly on delineation that can be readily tied in and a moderate development plan on current pads with total capital expenditures estimated at $50 million. This will allow production to average approximately 8,500 boe/d in 2027 while leaving debt manageable at less than $45 million compared to a $90 million credit facility. Acceleration of development will be commodity price dependent and concurrent with hedging to protect a strong balance sheet.

Current production is approximately 6,800 boe/d (Q3 2026 average to date of 6,700 boe/d). The wells are leveling off from Q2 after the initial flush period and we expect to exit 2026 over 9,000 boe/d with the four new wells anticipated to come on-stream in November. Note that Q3 2026 average production will also be affected by maintenance work on the Westcoast pipeline and at the McMahon plant that will shut in all of Coelacanth's production for the month of September.

Turning to corporate matters, I would like to welcome Jonathon Hanson as our VP Engineering and congratulate Jody Denis on his promotion to VP Operations. Mr. Hanson has 20 years of experience and will focus on exploitation and reservoir management. Mr. Denis joined the current management team in 2021 where he contributed to the success of Leucrotta Exploration Inc. in various roles before his well-earned promotion at Coelacanth.

(1) See news releases dated August 27, 2025 and April 22, 2026 for information relating to the Company's resources and reserves, and the Resources Data section of this document.

SUMMARY OF FINANCIAL RESULTS

($000s, except per share amounts)	Three Months Ended June 30 **2026**	2025	% Change	Six Months Ended June 30 **2026**	2025	% Change
Oil and natural gas sales	**23,200**	4,828	381	**45,363**	7,494	505
Cash flow from (used in) operating activities	**13,808**	(1,826)	(856)	**21,566**	(658)	(3,378)
Per share - basic and diluted (4)	**0.02**	(-)	(100)	**0.04**	(-)	(100)
Adjusted funds flow (used) (1)	**10,735**	(600)	(1,889)	**21,054**	(1,853)	(1,236)
Per share - basic and diluted	**0.02**	(-)	(100)	**0.04**	(-)	(100)
Net income (loss)	**3,960**	(3,464)	(214)	**7,800**	(7,081)	(210)
Per share - basic and diluted	**0.01**	(0.01)	(200)	**0.01**	(0.01)	(200)
Total assets				**287,469**	245,539	17
Total long-term liabilities				**25,883**	27,985	(8)
Adjusted working capital (deficiency) (2)				**6,529**	(38,035)	(117)
Net cash (debt) (3)				**6,529**	(38,035)	(117)

(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 (Used in) Operating Activities and Adjusted Funds Flow (Used)" section for a reconciliation from cash flow from (used in) operating activities.

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(3) Net cash (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, cash flow from operating activities, adjusted funds flow, and net income increased in the first half of 2026 compared to 2025 due to the initiation of commercial production at Two Rivers East in June 2025 and a successful drilling program in Q4 2025 with three new Lower Montney wells coming on-stream at the Two Rivers East 5-19 pad.

PRODUCTION

	Three Months Ended June 30 **2026**	2025	% Change	Six Months Ended June 30 **2026**	2025	% Change
Average Daily Production (1)						
Oil and condensate (bbls/d)	**1,613**	539	199	**1,758**	362	386
Other NGLs (bbls/d)	**392**	27	1,352	**347**	26	1,235
Oil and NGLs (bbls/d)	**2,005**	566	254	**2,105**	388	443
Natural gas (mcf/d)	**33,764**	3,861	774	**29,499**	3,588	722
Oil equivalent (boe/d)	**7,632**	1,210	531	**7,022**	986	612

(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 7,632 boe/d and 7,022 boe/d for the three and six months ended June 30, 2026, respectively, from 1,210 boe/d and 986 boe/d for the comparative periods in 2025. The increase in production was the result of the initiation of commercial production at Two Rivers East in June 2025 and a successful drilling program in Q4 2025 with three new Lower Montney wells coming on-stream at the Two Rivers East 5-19 pad.

Coelacanth's production profile for the second quarter of 2026 shifted more towards natural gas when compared to the comparative quarter in 2025 as the result of flush oil production in 2025 from initiation of commercial production at Two Rivers East which trends back to a higher natural gas weighting as the wells continue to produce. The Q2 2026 weighting was 74% natural gas (Q2 2025 - 53%) and 26% oil and NGLs (Q2 2025 - 47%).

OIL AND NATURAL GAS SALES	Three Months Ended June 30			Six Months Ended June 30		
($000s)	**2026**	2025	% Change	**2026**	2025	% Change
Oil and condensate	**16,951**	4,051	318	**32,050**	5,546	478
Other NGLs	**1,005**	66	1,423	**1,703**	151	1,028
Oil and NGLs	**17,956**	4,117	336	**33,753**	5,697	492
Natural gas	**5,244**	711	638	**11,610**	1,797	546
Total	**23,200**	4,828	381	**45,363**	7,494	505
Average Sales Price						
Oil and condensate ($/bbl)	**115.51**	82.58	40	**100.68**	84.51	19
Other NGLs ($/bbl)	**28.19**	26.96	5	**27.13**	32.19	(16)
Oil and NGLs ($/bbl)	**98.44**	79.91	23	**88.56**	81.01	9
Natural gas production sales and transportation revenue ($/mcf)	**1.71**	2.02	(15)	**2.17**	2.77	(22)
Combined ($/boe)	**33.41**	43.86	(24)	**35.69**	41.97	(15)

Revenue totaled $23.2 million and $45.4 million for the three and six months ended June 30, 2026, respectively, compared to $4.8 million and $7.5 million for the comparative periods in 2025. The increase in revenue was mainly the result of an increase in production due to the initiation of commercial production at Two Rivers East in June 2025 and a successful drilling program in Q4 2025 with three new Lower Montney wells coming on-stream at the Two Rivers East 5-19 pad. Higher oil commodity prices also contributed to the increase, however, the increase in production and oil prices was partially offset by lower natural gas commodity prices.

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

Commodity Pricing	Three Months Ended June 30			Six Months Ended June 30		
	2026	2025	% Change	**2026**	2025	% Change
Oil and NGLs						
Corporate price ($CDN/bbl) (1)						
- including physical sales contracts	**98.44**	79.91	23	**88.56**	81.01	9
- excluding physical sales contracts	**108.98**	79.91	36	**95.04**	81.01	17
Canadian light sweet ($CDN/bbl)	**131.28**	86.11	52	**112.82**	90.55	25
West Texas Intermediate ("WTI") ($US/bbl)	**92.99**	63.74	46	**82.46**	67.58	22
Natural gas						
Corporate price ($CDN/mcf) (1)						
- including physical sales contracts	**1.71**	2.02	(15)	**2.17**	2.77	(22)
- excluding physical sales contracts	**1.71**	2.02	(15)	**2.05**	2.77	(26)
AECO price ($CDN/mcf)	**1.60**	1.74	(8)	**1.80**	1.93	(7)
Westcoast Station 2 ($CDN/mcf)	**1.37**	0.39	251	**1.60**	0.79	103
Chicago City Gate ($US/mmbtu)	**2.47**	2.99	(17)	**3.87**	3.46	12
Exchange rate						
CDN/US dollar exchange rate	**0.7225**	0.7227	(-)	**0.7258**	0.7099	2

(1) 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.

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, excluding the effect of physical sales contracts, were 83.0% and 84.2% of Canadian light sweet prices for the three and six months ended June 30, 2026, respectively, down from 92.8% and 89.5% for the comparative periods in 2025. Coelacanth's liquids mix during the second quarter of 2026 was approximately 80% oil, condensate and pentanes, 11% butane and 9% propane (Q2 2025 - 91% oil, condensate and pentanes, 5% butane and 4% propane). The decrease in light oil, condensate and pentanes was due to the higher natural gas weighting and the associated butane and propane as wells come off flush oil production. This decrease in light oil, condensate and pentanes weighting attributed to the decrease in the Company's average oil and NGLs prices as a percentage of Canadian light sweet prices for the three and six months ended June 30, 2026.

Corporate average natural gas prices were 124.8% and 135.6% of Westcoast Station 2 price for the three and six months ended June 30, 2026, respectively, down from 517.9% and 350.6% for the comparative periods in 2025. The decrease 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.

Future prices received from the sale of the products may fluctuate as a result of market factors. In addition, the Company may enter into commodity price contracts to help manage future cash flows. The Company does not currently have any commodity price contracts outstanding.

ROYALTIES	**Three Months Ended June 30**			**Six Months Ended June 30**		
($000s)	**2026**	2025	% Change	**2026**	2025	% Change
Oil and NGLs	**2,284**	910	151	**4,052**	1,210	235
Natural gas	**120**	-	100	**439**	191	130
Total	**2,404**	910	164	**4,491**	1,401	221
Average Royalty Rate (% of sales)						
Oil and NGLs	**12.7**	22.1	(43)	**12.0**	21.2	(43)
Natural gas	**2.3**	-	100	**3.8**	10.6	(64)
Combined	**10.4**	18.8	(45)	**9.9**	18.7	(47)

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 $2.4 million and $4.5 million for the three and six months ended June 30, 2026, respectively, compared to $0.9 million and $1.4 million for the comparative periods in 2025. The increase was mainly due to the increased production and revenue at Two Rivers East partially offset by lower overall royalty rates. Royalty rates decreased as the result of a portion of the new 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 on gas wells and the first six months of equivalent production on oil wells. This transition royalty program relates to wells drilled on or after September 1, 2024 to December 31, 2026.

OPERATING EXPENSES	**Three Months Ended June 30**			**Six Months Ended June 30**		
	2026	2025	% Change	**2026**	2025	% Change
Operating expenses ($000s)	**5,160**	1,195	332	**9,653**	1,923	402
Operating expenses ($/boe)	**7.43**	10.86	(32)	**7.59**	10.77	(30)

Operating expenses increased to $5.2 million and $9.7 million for the three and six months ended June 30, 2026, respectively, compared to $1.2 million and $1.9 million for the comparative periods in 2025. The increase was mainly due to the increased production. Per unit operating expenses decreased to $7.43/boe and $7.59/boe for the three and six months ended June 30, 2026, respectively, from $10.86/boe and $10.77/boe in the comparative periods in 2025. The decrease is the result of increased production at Two Rivers East and being able to spread fixed facility costs across increased production volumes.

NET TRANSPORTATION EXPENSES	**Three Months Ended June 30**			**Six Months Ended June 30**		
($000s)	**2026**	2025	% Change	**2026**	2025	% Change
Oil and NGLs	**575**	228	152	**1,234**	271	355
Natural gas	**1,223**	248	393	**2,133**	479	345
Net transportation expenses (non-GAAP)	**1,798**	476	278	**3,367**	750	349
Unutilized transportation	**151**	303	(50)	**215**	580	(63)
Transportation expenses	**1,949**	779	150	**3,582**	1,330	169
Average transportation expenses						
Oil and NGLs ($/bbl)	**3.15**	4.43	(29)	**3.24**	3.86	(16)
Natural gas ($/mcf)	**0.40**	0.70	(43)	**0.40**	0.74	(46)
Net transportation expenses ($/boe)	**2.59**	4.33	(40)	**2.65**	4.20	(37)
Unutilized transportation ($/boe)	**0.22**	2.75	(92)	**0.17**	3.25	(95)
Transportation expenses ($/boe)	**2.81**	7.08	(60)	**2.82**	7.45	(62)

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 $1.9 million and $3.6 million for the three and six months ended June 30, 2026, respectively, compared to $0.8 million and $1.3 million for the comparative periods in 2025 mainly as the result of increased production and transportation commitments.

Net transportation expenses for oil and NGLs decreased on a per boe basis to $3.15/boe and $3.24/boe for the three and six months ended June 30, 2026, respectively, compared to $4.43/boe and $3.86/boe for the comparative periods in 2025. The decrease is mainly the result of the decreased oil content in the Company's product mix from new wells at Two Rivers East that have higher trucking costs.

Net transportation expenses for natural gas decreased on a per unit basis to $0.40/mcf for both the three and six months ended June 30, 2026, compared to $0.70/mcf and $0.74/mcf for the comparative periods in 2025. The decrease was mainly the 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 45.0 mmcf/d for July 1, 2026 through December 31, 2026.

OPERATING NETBACK	**Three Months Ended June 30**			**Six Months Ended June 30**		
($000s)	**2026**	2025	% Change	**2026**	2025	% Change
Oil and natural gas sales	**23,200**	4,828	381	**45,363**	7,494	505
Royalties	**(2,404)**	(910)	164	**(4,491)**	(1,401)	221
Operating expenses	**(5,160)**	(1,195)	332	**(9,653)**	(1,923)	402
Net transportation expenses (non-GAAP)	**(1,798)**	(476)	278	**(3,367)**	(750)	349
Operating netback (non-GAAP)	**13,838**	2,247	516	**27,852**	3,420	714
Depletion and depreciation	**(5,694)**	(1,405)	305	**(10,592)**	(2,384)	344
General and administrative expenses	**(1,707)**	(1,507)	13	**(3,350)**	(2,996)	12
Share based compensation	**(732)**	(1,135)	(36)	**(1,963)**	(2,399)	(18)
Finance expense	**(1,622)**	(1,432)	13	**(3,960)**	(2,313)	71
Finance income	**28**	71	(61)	**28**	171	(84)
Unutilized transportation	**(151)**	(303)	(50)	**(215)**	(580)	(63)
Net income (loss)	**3,960**	(3,464)	(214)	**7,800**	(7,081)	(210)

	Three Months Ended June 30			**Six Months Ended June 30**		
($/boe)	**2026**	2025	% Change	**2026**	2025	% Change
Oil and natural gas sales	**33.41**	43.86	(24)	**35.69**	41.97	(15)
Royalties	**(3.46)**	(8.26)	(58)	**(3.53)**	(7.85)	(55)
Operating expenses	**(7.43)**	(10.86)	(32)	**(7.59)**	(10.77)	(30)
Net transportation expenses (non-GAAP)	**(2.59)**	(4.33)	(40)	**(2.65)**	(4.20)	(37)
Operating netback (non-GAAP)	**19.93**	20.41	(2)	**21.92**	19.15	14
Depletion and depreciation	**(8.20)**	(12.76)	(36)	**(8.33)**	(13.35)	(38)
General and administrative expenses	**(2.46)**	(13.69)	(82)	**(2.64)**	(16.78)	(84)
Share based compensation	**(1.05)**	(10.31)	(90)	**(1.54)**	(13.43)	(89)
Finance expense	**(2.33)**	(13.02)	(82)	**(3.12)**	(12.96)	(76)
Finance income	**0.04**	0.64	(94)	**0.02**	0.96	(98)
Unutilized transportation	**(0.22)**	(2.75)	(92)	**(0.17)**	(3.25)	(95)
Net income (loss)	**5.71**	(31.48)	(118)	**6.14**	(39.66)	(115)

During the three and six months ended June 30, 2026, Coelacanth generated an operating netback (see "Non-GAAP and Other Financial Measures") of $19.93/boe and $21.92/boe, respectively, consistent with $20.41/boe and $19.15/boe for the comparative periods in 2025.

DEPLETION AND DEPRECIATION	**Three Months Ended June 30**			**Six Months Ended June 30**		
($000s)	**2026**	2025	% Change	**2026**	2025	% Change
Depletion and depreciation ($000s)	**5,694**	1,405	305	**10,592**	2,384	344
Depletion and depreciation ($/boe)	**8.20**	12.76	(36)	**8.33**	13.35	(38)

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 for the three and six months ended June 30, 2026 increased to $5.7 million and $10.6 million, respectively, from $1.4 million and $2.4 million for the comparative periods in 2025 as a result of increased production and cost base of PP&E. On a per boe basis, depletion and depreciation for the three and six months ended June 30, 2026 decreased to $8.20/boe and $8.33/boe, respectively, from $12.76/boe and $13.35/boe for the comparative periods in 2025 as a result of increased proved and probable reserves.

Included in depletion and depreciation expense for the three and six months ended June 30, 2026, is $33 thousand (June 30, 2025 - $21 thousand) and $65 thousand (June 30, 2025 - $43 thousand), respectively, related to the Company's right-of-use assets.

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

At June 30, 2026 and June 30, 2025, 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 June 30, 2026 and June 30, 2025, 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.

In June 2025, as a result of all wells being capable of production due to 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 on transfer and no impairment was recorded.

GENERAL AND ADMINISTRATIVE	**Three Months Ended June 30**			**Six Months Ended June 30**		
($000s)	**2026**	2025	% Change	**2026**	2025	% Change
G&A expenses (gross)	**1,773**	1,542	15	**3,505**	3,155	11
G&A capitalized	**(66)**	(35)	89	**(155)**	(159)	(3)
G&A expenses (net)	**1,707**	1,507	13	**3,350**	2,996	12
G&A expenses ($/boe)	**2.46**	13.69	(82)	**2.64**	16.78	(84)

During the three and six months ended June 30, 2026, net general and administrative ("G&A") expenses were $1.7 million and $3.4 million, respectively, consistent with $1.5 million and $3.0 million for the comparative periods in 2025.

On a per unit basis G&A decreased to $2.46/boe and $2.64/boe for the three and six months ended June 30, 2026, respectively, from $13.69/boe and $16.78/boe for the comparative periods in 2025 due to the increase in production at Two Rivers East.

SHARE BASED COMPENSATION	**Three Months Ended June 30**			**Six Months Ended June 30**		
($000s)	**2026**	2025	% Change	**2026**	2025	% Change
Share based compensation (gross)	**732**	1,330	(45)	**2,197**	2,784	(21)
Share based compensation (capitalized)	**-**	(195)	(100)	**(234)**	(385)	(39)
Share based compensation (net)	**732**	1,135	(36)	**1,963**	2,399	(18)
Share based compensation ($/boe)	**1.05**	10.31	(90)	**1.54**	13.43	(89)

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 decreased to $0.7 million and $2.0 million for the three and six months ended June 30, 2026, respectively, from $1.1 million and $2.4 million for the comparative periods in 2025 due to the reversal of share based compensation expense from forfeitures in Q2 2026. On a per unit basis share based compensation expenses for the three and six months ended June 30, 2026 decreased to $1.05/boe and $1.54/boe, respectively, from $10.31/boe and $13.43/boe for the comparative periods in 2025 as a result of increased production at Two Rivers East.

FINANCE EXPENSE	**Three Months Ended June 30**			**Six Months Ended June 30**		
($000s)	**2026**	2025	% Change	**2026**	2025	% Change
Interest expense on credit facility	**720**	559	29	**2,131**	976	118
Other obligations interest expense	**553**	212	161	**1,130**	217	421
Amortization of financing costs	**263**	187	41	**528**	374	41
Accretion of other obligations	**-**	409	(100)	**-**	614	(100)
Accretion of decommissioning obligations	**86**	65	32	**171**	132	30
Finance expense	**1,622**	1,432	13	**3,960**	2,313	71
Finance expense ($/boe)	**2.33**	13.02	(82)	**3.12**	12.96	(76)

Interest expense relates to interest expense and standby fees on the credit facility and outstanding letters of guarantee for firm transportation agreements and decommissioning obligations. The increase in 2026 stems from increasing the amount being drawn on its credit facilities throughout the second half of 2025 and the first quarter of 2026 as a result of capital expenditures during the past twelve months, before being repaid during Q2 2026. 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. The Company is required to repay the principal amount over a five-year period at an interest rate of 12.0% upon the commencement of the in-service date of the Company's Two Rivers East facility in June 2025. Accretion expense of decommissioning obligations increased for the three and six months ended June 30, 2026 compared to the same periods in 2025 as a result of higher risk-free rates used to calculate the net present value of the provision.

FINANCE INCOME

Finance income relates to interest earned on cash in the bank. Finance income totaled $28 thousand for both the three and six months ended June 30, 2026, compared to $71 thousand and $0.2 million for the comparative periods in 2025. 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 June 30, 2026 total approximately $325.3 million (December 31, 2025 - $325.9 million).

CASH FLOW FROM (USED IN) OPERATING ACTIVITIES AND ADJUSTED FUNDS FLOW (USED)

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

	Three Months Ended June 30			Six Months Ended June 30		
($000s)	**2026**	2025	% Change	**2026**	2025	% Change
Cash flow from (used in) operating activities	**13,808**	(1,826)	(856)	**21,566**	(658)	(3,378)
Add (deduct):						
Decommissioning expenditures	**12**	48	(75)	**30**	187	(84)
Change in non-cash working capital	**(3,085)**	1,178	(362)	**(542)**	(1,382)	(61)
Adjusted funds flow (used) (non-GAAP)	**10,735**	(600)	(1,889)	**21,054**	(1,853)	(1,236)

Adjusted funds flow (see "Non-GAAP and Other Financial Measures") was $10.7 million ($0.02 per basic and diluted share) and $21.1 million ($0.04 per basic and diluted share) for the three and six months ended June 30, 2026, respectively, compared to adjusted funds used of $0.6 million ($nil per basic and diluted share) and $1.9 million ($nil per basic and diluted share) for the comparative periods in 2025. The increase was the result of increased production partially offset by increased interest expense. The increased production 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 was $13.8 million ($0.02 per basic and diluted share) and $21.6 million ($0.04 per basic and diluted share) during the three and six months ended June 30, 2026, respectively, compared to cash flow used in operating activities of $1.8 million ($nil per basic and diluted share) and $0.7 million ($nil per basic and diluted share) for the comparative periods in 2025. Cash flow from (used in) operating activities differs from adjusted funds flow (used) due to the inclusion of changes in non-cash working capital and expenditures on decommissioning obligations. The increase in cash flow from operating activities is consistent with the increase in adjusted funds flow for the same reasons noted above.

NET INCOME (LOSS)

The Company earned net income of $4.0 million ($0.01 per basic and diluted share) and $7.8 million ($0.01 per basic and diluted share) for the three and six months ended June 30, 2026, respectively, compared to incurring net losses of $3.5 million ($0.01 per basic and diluted share) and $7.1 million ($0.01 per basic and diluted share) for the comparative periods in 2025. The change from net loss to net income was mainly the result of increased adjusted funds flow partially offset by increased depletion and depreciation resulting from increased production and cost base of PP&E.

CAPITAL EXPENDITURES	Three Months Ended June 30			Six Months Ended June 30		
($000s)	**2026**	2025	% Change	**2026**	2025	% Change
Land	**164**	196	(16)	**424**	396	7
Drilling, completions, and workovers	**1,875**	249	653	**5,740**	592	870
Equipment	**2,084**	13,803	(85)	**4,324**	38,904	(89)
Geological and geophysical	**345**	25	1,280	**784**	82	856
Total expenditures	**4,468**	14,273	(69)	**11,272**	39,974	(72)

During the three and six months ended June 30, 2026, the Company finalized work at the Two Rivers East facility providing additional capacity and water handling and continued the completions and start-up of three Lower Montney wells at Two Rivers East which were placed on production in Q1 2026. The Company also constructed its next pad at 9-32 in Two Rivers East to prepare for its Q3 2026 drilling program consisting of a four well Montney pad.

During the three and six months ended June 30, 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.

LIQUIDITY AND CAPITAL RESOURCES

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

($000s)	**June 30, 2026**	December 31, 2025	% Change
Current assets	**15,910**	6,119	160
Less:			
Current liabilities	**(14,182)**	(48,635)	(71)
Working capital (deficiency)	**1,728**	(42,516)	(104)
Add:			
Current portion of other obligations	**4,258**	4,037	5
Current portion of decommissioning obligations	**543**	545	(-)
Adjusted working capital (deficiency) (Capital management measure)	**6,529**	(37,934)	(117)
Credit facility, non-current	**-**	(38,101)	(100)
Net cash (debt) (Capital management measure)	**6,529**	(76,035)	(109)

To facilitate its capital expenditure program, the Company has a $90.0 million credit facility. At June 30, 2026, the Company had net cash of $6.5 million.

Production in the first half of 2026 has averaged 7,022 boe/d with the ramp up of new wells on production at Two Rivers East which has provided increased adjusted funds flow in 2026.

As at June 30, 2026, the Company had $nil drawn on its $90.0 million credit facility consisting of a $10.0 million operating facility and an $80.0 million syndicated facility. The operating and syndicated facilities revolve for a 364-day period and are subject to an additional 364-day extension subject to lender approval. If not extended, all outstanding advances would become repayable on May 30, 2028. The next scheduled borrowing base review of the credit facility is scheduled on or before November 30, 2026.

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%. The credit facility is secured by a $250.0 million fixed and floating charge debenture on the assets of the Company.

Repayments of principal are not required provided that the borrowings under the credit facility do not exceed the authorized borrowing amount and the Company is in compliance with covenants, representations and warranties. The borrowing base of the Company’s credit facility is subject to a semi-annual and annual review. A decrease in the borrowing base could result in a reduction to the credit facility, which may require a repayment to the lenders within 60 days. Covenants include reporting requirements, permitted indebtedness, permitted hedging and other standard business operating covenants. There are no financial covenants under the credit facility.

As at June 30, 2026, the Company has a standby letter of credit facility agreement with a third party of up to $10.0 million USD ($14.2 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%. At June 30, 2026, the Company has $12.0 million of standby letters of credit used against this facility (December 31, 2025 - $10.1 million).

During the three months ended June 30, 2026, the Company closed a bought-deal public financing issuing 97.6 million common shares of the Company at a price of $0.82 per share for gross proceeds of $80.0 million. The net proceeds were used to temporarily pay down the Company’s credit facility which amounts may be redrawn for exploration and development and general corporate purposes.

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 is to 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 financial liabilities, contractual obligations and commitments at June 30, 2026:

($000s)	**Total**	**Less than One Year**	**One to Three Years**	**After Three Years**
Accounts payable and accrued liabilities	9,381	9,381	-	-
Other obligations - principal	19,983	4,258	10,084	5,641
Decommissioning obligations	10,700	543	490	9,667
Operating commitments	1,503	291	594	618
Firm transportation agreements	169,588	5,614	18,825	145,149
Firm processing agreements	118,234	11,764	24,239	82,231
Total contractual obligations	329,389	31,851	54,232	243,306

Operating commitments include the non-lease variable components (operating expenses) of the head office lease.

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:

- 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, 2027.

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

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.

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)	**June 30, 2026**	August 24, 2026
Voting common shares	**633,850**	633,871
Warrants	**29,192**	29,192
Stock options	**24,614**	24,614
Restricted share units	**7,752**	7,731
Total	**695,408**	695,408

SUMMARY OF QUARTERLY RESULTS

	Q2 2026	Q1 2026	Q4 2025	Q3 2025	Q2 2025	Q1 2025	Q4 2024	Q3 2024
Average Daily Production								
Oil and NGLs (bbls/d)	**2,005**	2,208	1,316	1,464	566	209	502	254
Natural gas (mcf/d)	**33,764**	25,187	16,268	10,896	3,861	3,311	3,490	3,450
Oil equivalent (boe/d)	**7,632**	6,406	4,027	3,280	1,210	761	1,084	829
($000s, except per share amounts)								
Oil and natural gas sales	**23,200**	22,163	11,603	11,372	4,828	2,666	4,544	2,362
Cash flow from (used in) operating activities	**13,808**	7,758	4,852	4,712	(1,826)	1,168	3,157	(3,730)
Per share basic and diluted (2)	**0.02**	0.01	0.01	0.01	(-)	-	0.01	(0.01)
Adjusted funds flow (used) (1)	**10,735**	10,319	2,310	2,386	(600)	(1,253)	382	(207)
Per share basic and diluted	**0.02**	0.02	-	-	(-)	(-)	-	(-)
Net income (loss)	**3,960**	3,840	(2,181)	(1,764)	(3,464)	(3,617)	(2,903)	(2,464)
Per share basic and diluted	**0.01**	0.01	(-)	(-)	(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 (Used in) Operating Activities and Adjusted Funds Flow (Used)" section for a reconciliation from cash flow from (used in) 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 first six months of 2026 and the last six months of 2025 was the result of the initiation of commercial production at Two Rivers East and a successful drilling program at Two Rivers East in Q4 2025.

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.

On January 1, 2026, the Company adopted the amendments made to IFRS 9 Financial Instruments and IFRS 7 Financial Instruments: Disclosures. The amended standards include new guidance relating to settling financial liabilities using an electronic payment system and assessing contractual cash flow characteristics of financial assets. The adoption of these amendments did not have a material impact on the Company's financial statements.

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.

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 currency 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 June 30, 2026 was $nil (December 31, 2025 - $58.8 million). A 100 basis point increase or decrease in interest rates would have impacted net income by approximately $0.3 million for the six months ended June 30, 2026 (June 30, 2025 - $0.2 million).

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. The Company does not currently have any commodity price contracts in place.

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 petroleum 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 and accounts receivable on the statement of financial position. At June 30, 2026, $6.7 million (98%) of the Company's outstanding accounts receivable were current (<30 days) and $5 thousand (<1%) were outstanding for more than 90 days. During the six months ended June 30, 2026, the Company deemed $5 thousand of outstanding accounts receivable to be uncollectable (June 30, 2025 - $42 thousand).

Cash consists 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 a $90.0 million credit facility (refer to the "Liquidity and Capital Resources" section). At June 30, 2026, the Company had net cash of $6.5 million which includes $nil drawn under its credit facility.

During the three months ended June 30, 2026, the Company closed a bought-deal public financing issuing 97.6 million common shares of the Company at a price of $0.82 per share for gross proceeds of $80.0 million. The net proceeds were used to temporarily pay down the Company's credit facility which amounts may be redrawn for exploration and development and general corporate purposes.

With the completion of the initial Two Rivers East development project, and the resultant production from the 5-19 pad, the Company forecasts that it will have sufficient lending capacity and operational cash flows to meet its current and future obligations and to fund the other needs of the business for at least the next 12 months, pending commodity pricing, and operational performance. 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.

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.

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	**Q2 2026**	Q1 2026	Q4 2025	Q3 2025	Q2 2025	Q1 2025	Q4 2024	Q3 2024
Condensate (bbls/d)	**192**	166	109	46	17	18	22	33
Other NGLs (bbls/d)	**392**	301	165	92	27	25	29	33
NGLs (bbls/d)	**584**	467	274	138	44	43	51	66
Tight oil (bbls/d)	**1,421**	1,741	1,042	1,326	522	166	451	188
Condensate (bbls/d)	**192**	166	109	46	17	18	22	33
Oil and condensate (bbls/d)	**1,613**	1,907	1,151	1,372	539	184	473	221
Other NGLs (bbls/d)	**392**	301	165	92	27	25	29	33
Oil and NGLs (bbls/d)	**2,005**	2,208	1,316	1,464	566	209	502	254
Shale gas (mcf/d)	**33,764**	25,187	16,268	10,896	3,861	3,311	3,490	3,450
Natural gas (mcf/d)	**33,764**	25,187	16,268	10,896	3,861	3,311	3,490	3,450
Oil equivalent (boe/d)	**7,632**	6,406	4,027	3,280	1,210	761	1,084	829

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 adjusted working capital (deficiency), and net cash (debt). 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.

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. 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.

RESOURCES DATA

GLJ Ltd. provided a Resource Report effective June 30, 2025 on Coelacanth’s Two Rivers Montney lands encompassing approximately 150 net sections over four identified Montney zones. See news release dated August 27, 2025 for more details.

Total Petroleum Initially-In-Place (PIIP) is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered (equivalent to “total resources”).

Discovered Petroleum Initially-In-Place (equivalent to discovered resources) is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum initially in place includes production, reserves, and contingent resources; the remainder is unrecoverable.

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are further classified according to the level of certainty associated with the estimates and may be subclassified based on development and production status.

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent Resources are further classified in accordance with the level of certainty associated with the estimates and may be subclassified based on project maturity and/or characterized by their economic status.

Undiscovered Petroleum Initially-In-Place (equivalent to undiscovered resources) is that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. The recoverable portion of undiscovered petroleum initially in place is referred to as “prospective resources,” the remainder as “unrecoverable.”

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be subclassified based on project maturity.

There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. The key variables relevant to the evaluation are porosity, reservoir thickness, pressure, water saturation and gas composition which have increasing uncertainty, both positive and negative, with distance from existing wells.

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.

Coelacanth Energy Inc.
Condensed Interim Statements of Financial Position
(unaudited)

($000s)	Note	**June 30 2026**	December 31 2025
Assets			
Current assets			
Cash		**7,552**	-
Accounts receivable		**6,827**	5,645
Prepaid expenses and deposits		**1,531**	474
		15,910	6,119
Property, plant, and equipment	(4)	**242,087**	241,632
Exploration and evaluation assets	(5)	**29,472**	28,049
		271,559	269,681
		287,469	275,800
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities		**9,381**	24,278
Credit facility	(7)	**-**	19,775
Current portion of other obligations	(6)	**4,258**	4,037
Current portion of decommissioning obligations	(8)	**543**	545
		14,182	48,635
Credit facility	(7)	**-**	38,101
Other obligations	(6)	**15,726**	17,912
Decommissioning obligations	(8)	**10,157**	9,050
		40,065	113,698
Shareholders' Equity			
Shareholders' capital	(9)	**254,920**	177,319
Warrants	(9)	**4,986**	5,015
Contributed surplus		**12,118**	12,188
Deficit		**(24,620)**	(32,420)
		247,404	162,102
		287,469	275,800
Commitments	(16)		

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

Coelacanth Energy Inc.
Condensed Interim Statements of Operations and Comprehensive Income (Loss)
(unaudited)

($000s, except per share amounts)	Note	Three Months Ended June 30 **2026**	2025	Six Months Ended June 30 **2026**	2025
Revenue					
Oil and natural gas sales	(15)	**23,200**	4,828	**45,363**	7,494
Royalties		**(2,404)**	(910)	**(4,491)**	(1,401)
		20,796	3,918	**40,872**	6,093
Expenses					
Operating		**5,160**	1,195	**9,653**	1,923
Transportation		**1,949**	779	**3,582**	1,330
Depletion and depreciation	(4)	**5,694**	1,405	**10,592**	2,384
General and administrative		**1,707**	1,507	**3,350**	2,996
Share based compensation	(10)	**732**	1,135	**1,963**	2,399
Finance income		**(28)**	(71)	**(28)**	(171)
Finance expense		**1,622**	1,432	**3,960**	2,313
		16,836	7,382	**33,072**	13,174
Net income (loss) and comprehensive income (loss)		**3,960**	(3,464)	**7,800**	(7,081)
Net income (loss) per share					
Basic and diluted	(11)	**0.01**	(0.01)	**0.01**	(0.01)

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

Coelacanth Energy Inc.
Condensed Interim Statements of Shareholders' Equity
(unaudited)

($000s)	Note	Shareholders' Capital	Warrants	Contributed Surplus	Deficit	Total Equity
Balance, December 31, 2024		175,307	6,979	7,137	(21,394)	168,029
Net loss		-	-	-	(7,081)	(7,081)
Settlement of vested RSUs	(9)	1,543	-	(1,543)	-	-
Settlement of stock options	(10)	-	-	(104)	-	(104)
Expiry of warrants	(9)	-	(1,964)	1,964	-	-
Share based compensation	(10)	-	-	2,784	-	2,784
Balance, June 30, 2025		176,850	5,015	10,238	(28,475)	163,628
Balance, December 31, 2025		**177,319**	**5,015**	**12,188**	**(32,420)**	**162,102**
Net income		**-**	**-**	**-**	**7,800**	**7,800**
Share issuance, net of costs	(9)	**75,427**	**-**	**-**	**-**	**75,427**
Exercise of warrants	(9)	**79**	**(29)**	**-**	**-**	**50**
Settlement of vested RSUs	(9)	**2,095**	**-**	**(2,095)**	**-**	**-**
Settlement of stock options	(10)	**-**	**-**	**(172)**	**-**	**(172)**
Share based compensation	(10)	**-**	**-**	**2,197**	**-**	**2,197**
Balance, June 30, 2026		**254,920**	**4,986**	**12,118**	**(24,620)**	**247,404**

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

Coelacanth Energy Inc.
Condensed Interim Statements of Cash Flows

(unaudited)		Three Months Ended		Six Months Ended	
		June 30		June 30	
($000s)	Note	2026	2025	2026	2025
Operating Activities					
Net income (loss)		**3,960**	(3,464)	**7,800**	(7,081)
Depletion and depreciation	(4)	**5,694**	1,405	**10,592**	2,384
Share based compensation	(10)	**732**	1,135	**1,963**	2,399
Finance expense		**1,622**	1,432	**3,960**	2,313
Interest paid		**(1,273)**	(771)	**(3,261)**	(1,193)
Financing obligation payments		**-**	(337)	**-**	(675)
Decommissioning expenditures	(8)	**(12)**	(48)	**(30)**	(187)
Change in non-cash working capital	(14)	**3,085**	(1,178)	**542**	1,382
		13,808	(1,826)	**21,566**	(658)
Financing Activities					
Proceeds from (repayment of) credit facility	(7)	**(75,405)**	26,000	**(58,845)**	41,000
Debt issue costs	(7)	**(506)**	-	**(506)**	-
Proceeds from other obligations	(6)	**-**	-	**-**	22,658
Payment of other obligations	(6)	**(994)**	(322)	**(1,965)**	(349)
Proceeds from share issuance	(9)	**80,000**	-	**80,000**	-
Share issue costs	(9)	**(4,573)**	-	**(4,573)**	-
Exercise of warrants	(9)	**50**	-	**50**	-
Settlement of stock options	(10)	**(172)**	-	**(172)**	(104)
Change in non-cash working capital	(14)	**75**	-	**75**	-
		(1,525)	25,678	**14,064**	63,205
Investing Activities					
Capital expenditures - property, plant, and equipment	(4)	**(3,827)**	(370)	**(9,923)**	(1,038)
Capital expenditures - exploration and evaluation assets	(5)	**(641)**	(13,903)	**(1,349)**	(38,936)
Change in non-cash working capital	(14)	**(263)**	(8,821)	**(16,806)**	(26,440)
		(4,731)	(23,094)	**(28,078)**	(66,414)
Change in cash		**7,552**	758	**7,552**	(3,867)
Cash, beginning of period		**-**	1,068	**-**	5,693
Cash, end of period		**7,552**	1,826	**7,552**	1,826

The accompanying notes are an integral part of these condensed interim 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 condensed interim financial statements have been prepared in accordance with IFRS Accounting Standards (“IFRS”) as issued by the International Accounting Standards Board (“IASB”) applicable to the preparation of interim financial statements, as prescribed by IAS 34, Interim Financial Reporting. The condensed interim financial statements do not include all of the information and disclosure required in annual financial statements and should be read in conjunction with the audited financial statements and related notes for the year ended December 31, 2025.

The condensed interim financial statements were authorized for issuance by the Board of Directors on August 24, 2026.

(b) Basis of measurement

The condensed interim financial statements have been prepared on the historical cost basis.

Many of the Company’s oil and natural gas activities involve undivided interests in jointly owned assets and these condensed interim financial statements reflect only the Company’s proportionate interest in such activities.

(c) Functional and presentation currency

The condensed interim 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 condensed interim financial statements in conformity with IFRS requires management to make estimates and use judgment regarding the reported amounts of assets and liabilities as at the date of the condensed interim 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. The significant estimates and judgments made by management in the preparation of these condensed interim financial statements were consistent with those applied to the financial statements as at and for the year ended December 31, 2025.

3. MATERIAL ACCOUNTING POLICIES

The condensed interim financial statements have been prepared following the same accounting policies as the annual financial statements for the year ended December 31, 2025. The accounting policies have been applied consistently by the Company to all periods presented in these condensed interim financial statements.

On January 1, 2026, the Company adopted the amendments made to IFRS 9 Financial Instruments and IFRS 7 Financial Instruments: Disclosures. The amended standards include new guidance relating to settling financial liabilities using an electronic payment system and assessing contractual cash flow characteristics of financial assets. The adoption of these amendments did not have a material impact on the Company’s financial statements.

4. PROPERTY, PLANT, AND EQUIPMENT

Cost	Total
Balance, December 31, 2025	303,849
Additions	**9,923**
Capitalized share based compensation	**211**
Change in decommissioning obligation estimates (note 8)	**913**
Balance, June 30, 2026	**314,896**

Accumulated Depletion, Depreciation, and Impairment	Total
Balance, December 31, 2025	62,217
Depletion and depreciation	**10,592**
Balance, June 30, 2026	**72,809**

Net Book Value	Total
December 31, 2025	241,632
June 30, 2026	**242,087**

During the three and six months ended June 30, 2026, approximately $46 thousand (June 30, 2025 - $nil) and $119 thousand (June 30, 2025 - $9 thousand), respectively, of directly attributable general and administrative costs were capitalized as expenditures on property, plant, and equipment ("PP&E").

Depletion and depreciation

The calculation of depletion and depreciation expense for the three months ended June 30, 2026 included an estimated $111.5 million (June 30, 2025 - $101.8 million) for forecasted future development costs associated with proved and probable undeveloped oil and natural gas reserves and excluded approximately $8.9 million (June 30, 2025 - $6.9 million) for the estimated salvage value of production equipment and facilities. Depletion expense on development and production assets for the three and six months ended June 30, 2026 was $5.0 million (June 30, 2025 - $1.2 million) and $9.3 million (June 30, 2025 - $2.1 million), respectively.

Included in depletion and depreciation expense for the three and six months ended June 30, 2026, is $33 thousand (June 30, 2025 - $21 thousand) and $65 thousand (June 30, 2025 - $43 thousand), respectively, related to the Company's right-of-use assets. At June 30, 2026, the net book value of the right-of-use assets is $0.6 million (December 31, 2025 - $0.7 million).

Impairment assessment

The Company determined that there were no external or internal indicators of impairment or impairment reversal at June 30, 2026 for its PP&E Two Rivers CGU and no impairment test was required.

5. EXPLORATION AND EVALUATION ASSETS

	Total
Balance, December 31, 2025	28,049
Additions	**1,349**
Change in decommissioning obligation estimates (note 8)	**51**
Capitalized share based compensation	**23**
Balance, June 30, 2026	**29,472**

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 E&E 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.

During the three and six months ended June 30, 2026, approximately $12 thousand (June 30, 2025 - $35 thousand) and $36 thousand (June 30, 2025 - $150 thousand), respectively, of directly attributable general and administrative costs were capitalized as expenditures on E&E assets.

At June 30, 2026, 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.

6. OTHER OBLIGATIONS

	Pipeline obligation	Lease obligations	Total
Balance, December 31, 2025	21,153	796	21,949
Payments	**(3,018)**	**(77)**	**(3,095)**
Interest expense	**1,093**	**37**	**1,130**
Balance, June 30, 2026	**19,228**	**756**	**19,984**
Current	**4,172**	**86**	**4,258**
Long-term	**15,056**	**670**	**15,726**
	19,228	**756**	**19,984**

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 obligation

The Company has the following lease obligations in place as at June 30, 2026:

- 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:

	June 30, 2026
Within one year	154
Later than one year but not later than three years	379
Later than three years	436
Minimum lease payments	969
Amount representing interest expense	(213)
Present value of net lease and other obligation payments	**756**

7. CREDIT FACILITY

	Credit facility	Debt issue costs	Total
Balance, December 31, 2025	**58,845**	(969)	57,876
Repayment	**(58,845)**	-	(58,845)
Debt issue costs incurred	**-**	(506)	(506)
Debt issue costs amortized	**-**	528	528
Re-classified (note 14)	**-**	947	947
Balance, June 30, 2026	**-**	-	-

As at June 30, 2026, the Company had $nil drawn on its $90.0 million credit facility consisting of a $10.0 million operating facility and an $80.0 million syndicated facility. The operating and syndicated facilities revolve for a 364-day period and are subject to an additional 364-day extension subject to lender approval. If not extended, all outstanding advances would become repayable on May 30, 2028. The next scheduled borrowing base review of the credit facility is scheduled on or before November 30, 2026.

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%. The credit facility is secured by a $250.0 million fixed and floating charge debenture on the assets of the Company.

Repayments of principal are not required provided that the borrowings under the credit facility do not exceed the authorized borrowing amount and the Company is in compliance with covenants, representations and warranties. The borrowing base of the Company's credit facility is subject to a semi-annual and annual review. A decrease in the borrowing base could result in a reduction to the credit facility, which may require a repayment to the lenders within 60 days. Covenants include reporting requirements, permitted indebtedness, permitted hedging and other standard business operating covenants. There are no financial covenants under the credit facility.

As at June 30, 2026, the Company has a standby letter of credit facility agreement with a third party of up to $10.0 million USD ($14.2 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%. At June 30, 2026, the Company has $12.0 million of standby letters of credit used against this facility (December 31, 2025 - $10.1 million).

8. 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. The total undiscounted amount of the estimated cash flows, adjusted for inflation at 2.02% per year (December 31, 2025 - 1.93%) required to settle the decommissioning obligations is approximately $21.0 million (December 31, 2025 - $18.3 million) which is estimated to be incurred over the next 34 years. At June 30, 2026, a risk-free rate of 3.73% (December 31, 2025 - 3.80%) was used to calculate the net present value of the decommissioning obligations.

	Six Months Ended June 30, 2026	Year Ended December 31, 2025
Balance, beginning of period	**9,595**	9,649
Provisions incurred	**682**	675
Provisions settled	**(30)**	(421)
Revisions in estimated cash flows	**-**	(201)
Revisions due to change of rates	**282**	(395)
Accretion	**171**	288
Balance, end of period	**10,700**	9,595
Current	**543**	545
Long-term	**10,157**	9,050
	10,700	9,595

9. 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, 2025	533,465	177,319
Share issuance	**97,561**	**80,000**
Share issue costs	**-**	**(4,573)**
Exercise of warrants	**185**	**79**
Settlement of restricted share units	**2,639**	**2,095**
Balance, June 30, 2026	**633,850**	**254,920**

On May 6, 2026, the Company closed a bought-deal public financing through a syndicate of underwriters. The Company issued 97.6 million common shares of the Company at a price of $0.82 per common share for gross proceeds of $80.0 million (net proceeds of $75.4 million). The proceeds were used to pay down the Company's credit facility (see note 7).

Warrants	**Number**	**Amount**
Balance, December 31, 2025	29,377	5,015
Exercise of warrants	**(185)**	**(29)**
Balance, June 30, 2026	**29,192**	**4,986**

The following table summarizes the warrants outstanding and exercisable at June 30, 2026:

Issue Date	Expiry Date	Exercise Price	Number
June 10, 2022	June 10, 2027	$0.27	27,317
November 16, 2023	November 16, 2028	$0.80	1,875
			29,192

10. SHARE BASED COMPENSATION PLANS

Stock options

The Company has authorized and reserved for issuance 63.4 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 June 30, 2026, 24.6 million options were outstanding at an average exercise price of $0.76 per share.

	Number of Options	Weighted Average Exercise Price ($)
Balance, December 31, 2025	21,587	0.75
Granted	**8,634**	**0.80**
Settled	**(2,577)**	**0.77**
Forfeited	**(3,030)**	**0.80**
Balance, June 30, 2026	**24,614**	**0.76**
Exercisable, June 30, 2026	**12,490**	**0.72**

The following table summarizes the stock options outstanding and exercisable at June 30, 2026:

	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	3,829	1.1	0.55	3,695	0.54
$0.71 to $0.79	3,202	1.5	0.76	3,202	0.76
$0.80 to $0.83	17,583	3.6	0.80	5,593	0.80
	24,614	3.0	0.76	12,490	0.72

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:

	June 30, 2026	December 31, 2025
Risk-free interest rate (%)	**2.7**	2.9
Expected life (years)	**4.0**	4.0
Expected volatility (%)	**41.9**	49.0
Expected dividend yield (%)	**-**	-
Forfeiture rate (%)	**4.6**	6.9
Weighted average fair value of options granted ($ per option)	**0.29**	0.33

During the three and six months ended June 30, 2026, the Company recognized $0.2 million (June 30, 2025 - $0.6 million) and $0.8 million (June 30, 2025 - $1.3 million), respectively, of share based compensation related to the stock options. For the three months ended June 30, 2026, $0.2 million (June 30, 2025 - $0.5 million) was recognized as an expense and $nil (June 30, 2025 - $87 thousand) was capitalized. For the six months ended June 30, 2026, $0.7 million (June 30, 2025 - $1.1 million) was recognized as an expense and $95 thousand (June 30, 2025 - $0.2 million) was capitalized. At June 30, 2026 there was $1.9 million remaining as unrecognized share based compensation related to the stock options.

During the three and six months ended June 30, 2026, the Company settled 2.6 million stock options for $172 thousand in cash (six months ended June 30, 2025 - 0.3 million stock options for $104 thousand in cash).

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, 2025	6,348
Granted	**5,369**
Exercised	**(2,639)**
Forfeited	**(1,326)**
Balance, June 30, 2026	**7,752**
Exercisable, June 30, 2026	**-**

The weighted average market price of the Company's common shares used to value the RSUs granted during the six months ended June 30, 2026 was $0.80 (June 30, 2025 - $0.81). During the three and six months ended June 30, 2026, the Company recognized $0.6 million (June 30, 2025 - $0.7 million) and $1.4 million (June 30, 2025 - $1.5 million) of share based compensation related to the RSUs. For the three months ended June 30, 2026, $0.6 million (June 30, 2025 - $0.6 million) was recognized as an expense and $nil (June 30, 2025 - $0.1 million) was capitalized. For the six months ended June 30, 2026, $1.3 million (June 30, 2025 - $1.3 million) was recognized as an expense and $0.1 million (June 30, 2025 - $0.2 million) was capitalized. At June 30, 2026, there was $3.5 million remaining as unrecognized share based compensation related to the RSUs.

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 paid 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.

11. PER SHARE AMOUNTS

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

	Three Months Ended June 30		Six Months Ended June 30	
	2026	2025	**2026**	2025
Weighted average number of shares - basic	**596,166**	532,274	**565,827**	531,862
Dilutive effect of share based compensation plans and warrants	**24,269**	-	**24,269**	-
Weighted average number of shares - diluted	**620,435**	532,274	**590,096**	531,862

For the three months ended June 30, 2026, 11.5 million stock options (June 30, 2025 - 22.4 million), nil RSUs (June 30, 2025 - 6.9 million), and nil warrants (June 30, 2025 - 29.4 million) were excluded from the weighted-average share calculation because they were anti-dilutive.

For the six months ended June 30, 2026, 11.5 million stock options (June 30, 2025 - 22.4 million), nil RSUs (June 30, 2025 - 6.9 million), and nil warrants (June 30, 2025 - 29.4 million) were excluded from the weighted-average share calculation because they were anti-dilutive.

12. 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 currency 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 June 30, 2026 was $nil (December 31, 2025 - $58.8 million). A 100 basis point increase or decrease in interest rates would have impacted net income by approximately $0.3 million for the six months ended June 30, 2026 (June 30, 2025 - $0.2 million).

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. The Company does not currently have any commodity price contracts in place.

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 and accounts receivable on the statement of financial position. At June 30, 2026, $6.7 million (98%) of the Company's outstanding accounts receivable were current (<30 days) and $5 thousand (<1%) were outstanding for more than 90 days. During the six months ended June 30, 2026, the Company deemed $5 thousand of outstanding accounts receivable to be uncollectable (June 30, 2025 - $42 thousand).

Cash consists 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 a $90.0 million credit facility (see note 7). At June 30, 2026, the Company had net cash of $6.5 million (see note 13) which includes $nil drawn under its credit facility.

During the three months ended June 30, 2026, the Company closed a bought-deal public financing issuing 97.6 million common shares of the Company at a price of $0.82 per share for gross proceeds of $80.0 million. The net proceeds were used to temporarily pay down the Company's credit facility which amounts may be redrawn for exploration and development and general corporate purposes.

With the completion of the initial Two Rivers East development project, and the resultant production from the 5-19 pad, the Company forecasts that it will have sufficient lending capacity and operational cash flows to meet its current and future obligations and to fund the other needs of the business for at least the next 12 months, pending commodity pricing, and operational performance. 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.

13. 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 cash (debt). Adjusted working capital (deficiency) includes current assets less current liabilities, excluding the current portion of decommissioning obligations and other obligations. Net cash (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.

	June 30, 2026	December 31, 2025
Shareholders' equity	**247,404**	162,102
Net cash (debt)	**6,529**	(76,035)

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

($000s)	**June 30, 2026**	December 31, 2025
Current assets	**15,910**	6,119
Less:		
Current liabilities	**(14,182)**	(48,635)
Working capital (deficiency)	**1,728**	(42,516)
Add:		
Current portion of other obligations	**4,258**	4,037
Current portion of decommissioning obligations	**543**	545
Adjusted working capital (deficiency)	**6,529**	(37,934)
Credit facility, non-current	**-**	(38,101)
Net cash (debt)	**6,529**	(76,035)

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.

14. SUPPLEMENTAL CASH FLOW INFORMATION

	Three Months Ended June 30		**Six Months Ended June 30**	
	2026	2025	**2026**	2025
Accounts receivable	**2,687**	(2,130)	**(1,182)**	586
Prepaid expenses and deposits(1)	**(256)**	(120)	**(110)**	(9)
Accounts payable and accrued liabilities	**466**	(7,749)	**(14,897)**	(25,635)
Change in non-cash working capital	**2,897**	(9,999)	**(16,189)**	(25,058)
Relating to:				
Operating	**3,085**	(1,178)	**542**	1,382
Financing	**75**	-	**75**	-
Investing	**(263)**	(8,821)	**(16,806)**	(26,440)
Change in non-cash working capital	**2,897**	(9,999)	**(16,189)**	(25,058)

(1) For the three and six months ended June 30, 2026, excludes $0.9 million (June 30, 2025 - $0.5 million) of debt issuance costs that were re-classified.

15. 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:

	Three Months Ended June 30		Six Months Ended June 30	
	2026	2025	**2026**	2025
Oil and condensate	**16,951**	4,051	**32,050**	5,546
Other natural gas liquids	**1,005**	66	**1,703**	151
Natural gas	**5,244**	711	**11,610**	1,797
Total revenue	**23,200**	4,828	**45,363**	7,494

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:

	Three Months Ended June 30		Six Months Ended June 30	
	2026	2025	**2026**	2025
Natural gas production sales	**4,067**	467	**9,537**	1,325
Transportation revenue	**1,177**	244	**2,073**	472
Natural gas sales	**5,244**	711	**11,610**	1,797

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 87% for the six months ended June 30, 2026 (June 30, 2025 - three customers represented combined sales of 93%).

16. COMMITMENTS

The following is a summary of the Company's contractual obligations and commitments at June 30, 2026:

	2026	2027	2028	2029	2030	Thereafter	Total
Operating commitments	142	297	297	297	297	173	1,503
Firm transportation agreements	2,807	5,950	9,912	11,540	11,540	127,839	169,588
Firm processing agreements	5,824	11,881	12,118	12,360	12,608	63,443	118,234
	8,773	18,128	22,327	24,197	24,445	191,455	289,325

Operating commitments include the non-lease variable components (operating expenses) of the head office (see note 6).

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:

- 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, 2027.

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

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 6).

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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).

COELACANTH
ENERGY INC.