

# Q1 2026 RESULTS



FINANCIAL AND OPERATING RESULTS FOR THE  
THREE MONTHS ENDED MARCH 31, 2026

## HIGHLIGHTS

- Increased oil and natural gas production 742% to 6,406 boe/d in Q1 2026 from 761 boe/d in Q1 2025. Exit Q1 2026 production was approximately 8,000 boe/d with the ramp up of new wells on production at Two Rivers East.
- Subsequent to March 31, 2026, amended and restated the credit facility to extend and increase the credit facility from \$80.0 million to \$90.0 million.
- Subsequent to March 31, 2026, 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 (\$000s, except per share amounts)	THREE MONTHS ENDED MARCH 31		
	2026	2025	% Change
OIL AND NATURAL GAS SALES	22,163	2,666	731
CASH FLOW FROM OPERATING ACTIVITIES	7,758	1,168	564
Per share - basic and diluted <sup>(1)</sup>	0.01	-	100
ADJUSTED FUNDS FLOW (USED) <sup>(2)</sup>	10,319	(1,253)	(924)
Per share - basic and diluted	0.02	(-)	(100)
NET INCOME (LOSS)	3,840	(3,617)	(206)
Per share - basic and diluted	0.01	(0.01)	(200)
CAPITAL EXPENDITURES <sup>(3)</sup>	6,804	25,701	(74)
ADJUSTED WORKING CAPITAL DEFICIENCY <sup>(4)</sup>	(18,983)	(22,942)	(17)
NET DEBT <sup>(5)</sup>	(73,774)	(22,942)	222
COMMON SHARES OUTSTANDING (000s)			
Weighted average - basic	535,151	531,445	1
Weighted average - diluted	558,203	531,445	5
End of period - basic	536,104	532,202	1
End of period - fully diluted	604,705	624,877	(3)

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

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

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

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

OPERATING RESULTS <sup>(1)</sup>	Three Months Ended		
	March 31		
	2026	2025	% Change
<b>Daily production <sup>(2)</sup></b>			
Oil and condensate (bbls/d)	1,907	184	936
Other NGLs (bbls/d)	301	25	1,104
Oil and NGLs (bbls/d)	2,208	209	956
Natural gas (mcf/d)	25,187	3,311	661
Oil equivalent (boe/d)	6,406	761	742
<b>Oil and natural gas sales</b>			
Oil and condensate (\$/bbl)	87.99	90.21	(2)
Other NGLs (\$/bbl)	25.73	38.01	(32)
Oil and NGLs (\$/bbl)	79.49	84.03	(5)
Natural gas (\$/mcf)	2.81	3.65	(23)
Oil equivalent (\$/boe)	38.44	38.94	(1)
<b>Operating netback and net income (loss) (\$/boe)</b>			
Oil and natural gas sales	38.44	38.94	(1)
Royalties	(3.62)	(7.18)	(50)
Operating expenses	(7.79)	(10.63)	(27)
Net transportation expenses <sup>(3)</sup>	(2.72)	(4.00)	(32)
<b>Operating netback <sup>(4)</sup></b>	<b>24.31</b>	<b>17.13</b>	<b>42</b>
Depletion and depreciation (\$/boe)	(8.50)	(14.30)	(41)
General and administrative expenses (\$/boe)	(2.85)	(21.76)	(87)
Share based compensation (\$/boe)	(2.13)	(18.46)	(88)
Finance expense (\$/boe)	(4.06)	(12.86)	(68)
Finance income (\$/boe)	-	1.46	(100)
Unutilized transportation (\$/boe)	(0.11)	(4.05)	(97)
<b>Net income (loss) (\$/boe)</b>	<b>6.66</b>	<b>(52.84)</b>	<b>(113)</b>

- (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")

May 26, 2026

The MD&A should be read in conjunction with the unaudited condensed interim financial statements and related notes for the three months ended March 31, 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
GJ	Gigajoules
GJ/d	Gigajoules per day

#### **Oil Equivalent**

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

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

### NOTE REGARDING PRODUCT TYPES

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

**Natural gas** refers to shale gas.

**Oil and condensate** refers to condensate and tight oil combined.

**Other NGLs** refers to butane, propane and ethane combined.

**Oil and NGLs** refers to tight oil and NGLs combined.

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

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

### NON-GAAP AND OTHER FINANCIAL MEASURES

This MD&A refers to certain measures that are not determined in accordance with IFRS (or "GAAP"). These non-GAAP and other financial measures do not have any standardized meaning prescribed under IFRS and therefore may not be comparable to similar measures presented by other entities. The non-GAAP and other financial measures should not be considered alternatives to, or more meaningful than, financial measures that are determined in accordance with IFRS as indicators of the Company's performance. Management believes that the presentation of these non-GAAP and other financial measures provides useful information to shareholders and investors in understanding and evaluating the Company's ongoing operating performance, and the measures provide increased transparency to better analyze the Company's performance against prior periods on a comparable basis.

#### **Non-GAAP Financial Measures**

##### **Adjusted funds flow (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. Adjusted funds flow (used) is a non-GAAP financial measure and has been defined by the Company as cash flow from operating activities excluding the

change in non-cash working capital related to operating activities 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 operating activities under the heading "Cash Flow From 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	
	March 31	
(\$000s)	2026	2025
Transportation expenses	1,633	551
Unutilized transportation	(64)	(277)
Net transportation expenses (non-GAAP)	1,569	274

#### **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	
	March 31	
(\$000s)	2026	2025
Oil and natural gas sales	22,163	2,666
Royalties	(2,087)	(491)
Operating expenses	(4,493)	(728)
Net transportation expenses	(1,569)	(274)
Operating netback (non-GAAP)	14,014	1,173

#### **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	
	March 31	
(\$000s)	2026	2025
Capital expenditures – property, plant, and equipment	6,096	668
Capital expenditures – exploration and evaluation assets	708	25,033
Capital expenditures (non-GAAP)	6,804	25,701

#### **Capital Management Measures**

##### **Adjusted working capital deficiency and net debt**

Management uses adjusted working capital deficiency and net debt as measures to assess the Company's financial position. Adjusted working capital deficiency is calculated as current assets less current liabilities, excluding the current portion of decommissioning obligations and other obligations. Net debt includes adjusted working capital deficiency and non-current portion of the credit facility. Refer to the calculation of adjusted working capital deficiency and reconciliation to working capital deficiency and net 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 oil and natural gas assets on a per unit of production basis. Operating netback per boe is calculated as operating netback divided by total production for the applicable period. Operating netback per boe is reconciled to net 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 Q1 2026, Coelacanth completed the final construction of its Two Rivers East facility and placed its 5-19 pad wells on production systematically throughout the quarter yielding an average production rate of approximately 6,400 boe/d and a quarterly exit rate of approximately 8,000 boe/d.

Now that production is established on a small portion of the land base, Coelacanth will look to delineate its large Montney resource with further step-out and development drilling to better understand the ultimate capability of this property.

Operations to date have allowed us to refine both our geological model and operational design, increasing our confidence in our undeveloped land base (150 contiguous sections) that is 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.<sup>(1)</sup>

Although we remain cautious given existing natural gas prices in Canada, the recent financing will also allow us to accelerate capital to further the overall business plan.

I also wish to thank Bret Kimpton (COO), who will be retiring from the Company to pursue other endeavors. Bret was a key contributor in the planning and construction of the Two Rivers Facility and related infrastructure that was on time and on budget. His current duties will be transitioned to other members of the Coelacanth team through the summer.

*(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		
	2026	March 31 2025	% Change
<b>Oil and natural gas sales</b>	<b>22,163</b>	2,666	731
<b>Cash flow from operating activities</b>	<b>7,758</b>	1,168	564
Per share - basic and diluted <sup>(4)</sup>	<b>0.01</b>	-	100
<b>Adjusted funds flow (used) <sup>(1)</sup></b>	<b>10,319</b>	(1,253)	(924)
Per share - basic and diluted	<b>0.02</b>	(-)	(100)
<b>Net income (loss)</b>	<b>3,840</b>	(3,617)	(206)
Per share - basic and diluted	<b>0.01</b>	(0.01)	(200)
<b>Total assets</b>	<b>281,748</b>	229,997	23
<b>Total long-term liabilities</b>	<b>80,824</b>	28,226	186
<b>Adjusted working capital deficiency <sup>(2)</sup></b>	<b>(18,983)</b>	(22,942)	(17)
<b>Net debt <sup>(3)</sup></b>	<b>(73,774)</b>	(22,942)	222

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

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

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

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

Oil and natural gas sales, cash flow from operating activities, adjusted funds flow, and net income increased in Q1 2026 compared to Q1 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		
	March 31		
	2026	2025	% Change
Average Daily Production <sup>(1)</sup>			
Oil and condensate (bbls/d)	1,907	184	936
Other NGLs (bbls/d)	301	25	1,104
Oil and NGLs (bbls/d)	2,208	209	956
Natural gas (mcf/d)	25,187	3,311	661
Oil equivalent (boe/d)	6,406	761	742

(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 6,406 boe/d for the three months ended March 31, 2026 from 761 boe/d for the comparative period in 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.

Coelacanth's production profile for the first quarter of 2026 was comprised of higher oil and NGLs content when compared to the comparative period in 2025 as the result of increased oil content from new wells put on-stream at Two Rivers East from successful drilling in Q4 2025. The Q1 2026 weighting was 66% natural gas (Q1 2025 - 73%) and 34% oil and NGLs (Q1 2025 - 27%). As the wells mature, it is expected that the production mix will become more gas weighted.

## OIL AND NATURAL GAS SALES

(\$000s)	Three Months Ended		
	March 31		
	2026	2025	% Change
Oil and condensate	15,099	1,495	910
Other NGLs	698	85	721
Oil and NGLs	15,797	1,580	900
Natural gas	6,366	1,086	486
Total	22,163	2,666	731
Average Sales Price			
Oil and condensate (\$/bbl)	87.99	90.21	(2)
Other NGLs (\$/bbl)	25.73	38.01	(32)
Oil and NGLs (\$/bbl)	79.49	84.03	(5)
Natural gas production sales and transportation revenue (\$/mcf)	2.81	3.65	(23)
Combined (\$/boe)	38.44	38.94	(1)

Revenue increased to \$22.2 million for the three months ended March 31, 2026, from \$2.7 million for the comparative period 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. This increase was partially offset by lower oil, NGLs, and natural gas commodity prices.

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

Commodity Pricing	Three Months Ended		
	March 31		
	2026	2025	% Change
<b>Oil and NGLs</b>			
Corporate price (\$CDN/bbl)	79.49	84.03	(5)
Canadian light sweet (\$CDN/bbl)	94.37	94.99	(1)
West Texas Intermediate ("WTI") (\$US/bbl)	71.93	71.42	1
<b>Natural gas</b>			
Corporate price (\$CDN/mcf)	2.81	3.65	(23)
AECO price (\$CDN/mcf)	2.00	2.13	(6)
Westcoast Station 2 (\$CDN/mcf)	1.82	1.22	49
Chicago City Gate (\$US/mmbtu)	5.28	4.02	31
<b>Exchange rate</b>			
CDN/US dollar exchange rate	0.7291	0.6972	5

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

The Company's corporate average oil and NGLs prices were 84.2% of Canadian light sweet prices for the three months ended March 31, 2026, consistent with 88.5% for the comparative period in 2025. Coelacanth's liquids mix during the first quarter of 2026 was approximately 86% light oil, condensate and pentanes, 8% butane and 6% propane (Q1 2025 - 88% light oil, condensate and pentanes, 5% butane and 7% propane).

Corporate average natural gas prices were 154.4% of Westcoast Station 2 price for the three months ended March 31, 2026, down from 299.2% for the comparative period 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.

At March 31, 2026, the Company had the following physical commodity price contracts outstanding:

Commodity	Period	Type of Contract	Quantity	Contract Price
Oil	April 1, 2026 - April 30, 2026	Physical Sales	500 bbls/d	WTI CDN \$86.86/bbl
Oil	May 1, 2026 - June 30, 2026	Physical Sales	500 bbls/d	WTI CDN \$85.69/bbl

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

ROYALTIES	Three Months Ended		
	March 31		
(\$000s)	2026	2025	% Change
Oil and NGLs	1,768	300	489
Natural gas	319	191	67
Royalties	2,087	491	325
<b>Average Royalty Rate (% of sales)</b>			
Oil and NGLs	11.2	19.0	(41)
Natural gas	5.0	17.6	(72)
Combined	9.4	18.4	(49)

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 increased to \$2.1 million for the three months ended March 31, 2026, from \$0.5 million for the comparative period in 2025. The increase was mainly due to the increased production and revenue at Two Rivers East partially offset by lower royalty rates. Royalty rates decreased as the result of a portion of the new oil wells at Two Rivers East being subject to British Columbia's flat 5.0% transition royalty rate for the first twelve months of equivalent production on gas wells and the first six months of equivalent production on oil wells. This transition royalty program relates to oil wells drilled on or after September 1, 2024 to December 31, 2026.

**OPERATING EXPENSES**

	Three Months Ended		
	March 31		
	2026	2025	% Change
Operating expenses (\$000s)	4,493	728	517
Operating expenses (\$/boe)	7.79	10.63	(27)

Operating expenses increased to \$4.5 million for the three months ended March 31, 2026, from \$0.7 million for the comparative period in 2025. The increase was mainly due to the increased production. Per unit operating expenses decreased to \$7.79/boe for the three months ended March 31, 2026, from \$10.63/boe in the comparative period in 2025 also as a result of increased production at Two Rivers East and being able to spread fixed facility costs across increased production volumes.

**NET TRANSPORTATION EXPENSES**

(\$000s)	Three Months Ended		
	March 31		
	2026	2025	% Change
Oil and NGLs	659	43	1,433
Natural gas	910	231	294
Net transportation expenses (non-GAAP)	1,569	274	473
Unutilized transportation	64	277	(77)
Transportation expenses	1,633	551	196
<b>Average transportation expenses</b>			
Oil and NGLs (\$/bbl)	3.32	2.27	46
Natural gas (\$/mcf)	0.40	0.78	(49)
Net transportation expenses (\$/boe)	2.72	4.00	(32)
Unutilized transportation (\$/boe)	0.11	4.05	(97)
Transportation expenses (\$/boe)	2.83	8.05	(65)

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 \$1.6 million for the three months ended March 31, 2026, from \$0.6 million for the comparative period in 2025 mainly as the result of increased production and transportation commitments.

Net transportation expenses for oil and NGLs increased on a per boe basis to \$3.32/boe for the three months ended March 31, 2026, compared to \$2.27/boe for the comparative period in 2025. The increase was mainly the result of the increased oil content in the Company's product mix from new oil 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 the three months ended March 31, 2026, compared to \$0.78/mcf for the comparative period 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 from April 1, 2026 through December 31, 2026.

OPERATING NETBACK	Three Months Ended		
	March 31		
(\$000s)	2026	2025	% Change
Oil and natural gas sales	22,163	2,666	731
Royalties	(2,087)	(491)	325
Operating expenses	(4,493)	(728)	517
Net transportation expenses (non-GAAP)	(1,569)	(274)	473
<b>Operating netback (non-GAAP)</b>	<b>14,014</b>	<b>1,173</b>	<b>1,095</b>
Depletion and depreciation	(4,898)	(979)	400
General and administrative expenses	(1,643)	(1,489)	10
Share based compensation	(1,231)	(1,264)	(3)
Finance expense	(2,338)	(881)	165
Finance income	-	100	(100)
Unutilized transportation	(64)	(277)	(77)
<b>Net income (loss)</b>	<b>3,840</b>	<b>(3,617)</b>	<b>(206)</b>

	Three Months Ended		
	March 31		
(\$/boe)	2026	2025	% Change
Oil and natural gas sales	38.44	38.94	(1)
Royalties	(3.62)	(7.18)	(50)
Operating expenses	(7.79)	(10.63)	(27)
Net transportation expenses (non-GAAP)	(2.72)	(4.00)	(32)
<b>Operating netback (non-GAAP)</b>	<b>24.31</b>	<b>17.13</b>	<b>42</b>
Depletion and depreciation	(8.50)	(14.30)	(41)
General and administrative expenses	(2.85)	(21.76)	(87)
Share based compensation	(2.13)	(18.46)	(88)
Finance expense	(4.06)	(12.86)	(68)
Finance income	-	1.46	(100)
Unutilized transportation	(0.11)	(4.05)	(97)
<b>Net income (loss)</b>	<b>6.66</b>	<b>(52.84)</b>	<b>(113)</b>

During the three months ended March 31, 2026, Coelacanth generated an operating netback (see “Non-GAAP and Other Financial Measures”) of \$24.31/boe, compared to \$17.13/boe for the comparative period in 2025. The increase was mainly the result of lower royalties, operating expenses and net transportation expenses discussed above.

DEPLETION AND DEPRECIATION	Three Months Ended		
	March 31		
	2026	2025	% Change
Depletion and depreciation (\$000s)	4,898	979	400
Depletion and depreciation (\$/boe)	8.50	14.30	(41)

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 months ended March 31, 2026 increased to \$4.9 million from \$1.0 million for the comparative period in 2025 as a result of increased production and cost base of PP&E. The Company commenced depleting and depreciating the Two Rivers East development project costs in June 2025 upon the transfer from exploration and evaluation assets to PP&E. On a per boe basis, depletion and depreciation for the three months ended March 31, 2026 decreased to \$8.50/boe, from \$14.30/boe for the comparative period in 2025 as a result of increased proved and probable reserves.

Included in depletion and depreciation expense for the three months ended March 31, 2026 is \$32 thousand (March 31, 2025 - \$22 thousand) related to the Company’s right-of-use assets.

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

At March 31, 2026 and March 31, 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 March 31, 2026 and March 31, 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.

**GENERAL AND ADMINISTRATIVE**

(\$000s)	Three Months Ended		
	March 31		
	2026	2025	% Change
G&A expenses (gross)	1,732	1,613	7
G&A capitalized	(89)	(124)	(28)
G&A expenses (net)	1,643	1,489	10
G&A expenses (\$/boe)	2.85	21.76	(87)

Net general and administrative (“G&A”) expenses totaled \$1.6 million for the three months ended March 31, 2026, consistent with \$1.5 million for the comparative period in 2025.

On a per unit basis G&A decreased to \$2.85/boe for the three months ended March 31, 2026 from \$21.76/boe for the comparative period in 2025 due to the increase in production at Two Rivers East.

**SHARE BASED COMPENSATION**

(\$000s)	Three Months Ended		
	March 31		
	2026	2025	% Change
Share based compensation (gross)	1,465	1,454	1
Share based compensation (capitalized)	(234)	(190)	23
Share based compensation (net)	1,231	1,264	(3)
Share based compensation (\$/boe)	2.13	18.46	(88)

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

Share based compensation expense totaled \$1.2 million for the three months ended March 31, 2026, consistent with \$1.3 million for the comparative period in 2025. On a per unit basis share based compensation expenses decreased in Q1 2026 from Q1 2025 due to the increased production at Two Rivers East.

**FINANCE EXPENSE**

	Three Months Ended		
	March 31		
	2026	2025	% Change
Interest expense on credit facility	1,411	417	238
Other obligations interest expense	577	5	11,440
Amortization of financing costs	265	187	42
Accretion of other obligations	-	205	(100)
Accretion of decommissioning obligations	85	67	27
Finance expense	2,338	881	165
Finance expense (\$/boe)	4.06	12.86	(68)

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 large increase stems from moving from a positive cash balance at December 31, 2024 to being drawn \$75.4 million on its credit facilities at March 31, 2026 as a result of capital expenditures during the past twelve months. The increase in interest on other obligations is the result of a \$22.7 million obligation to a midstream company funding the extension of their gathering system to connect to the Company’s Two Rivers East project. Commencing June 2025, the Company is required to repay the principal amount over a five-year period at an interest rate of 12.0%. Accretion expense on decommissioning obligations was consistent for the three months ended March 31, 2026 compared to the same period in 2025.

**FINANCE INCOME**

Finance income relates to interest earned on cash in the bank. Finance income totaled \$nil for the three months ended March 31, 2026 compared to \$0.1 million for the comparative period 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 March 31, 2026 total approximately \$325.5 million (December 31, 2025 - \$325.9 million).

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

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

(\$000s)	Three Months Ended		
	March 31		
	2026	2025	% Change
Cash flow from operating activities	7,758	1,168	564
Add (deduct):			
Decommissioning expenditures	18	139	(87)
Change in non-cash working capital	2,543	(2,560)	(199)
Adjusted funds flow (used) (non-GAAP)	10,319	(1,253)	(924)

Adjusted funds flow (see "Non-GAAP and Other Financial Measures") was \$10.3 million (\$0.02 per basic and diluted share) for the three months ended March 31, 2026 and adjusted funds used was \$1.3 million (\$nil per basic and diluted share) for the comparative period in 2025. The increase was the result of increased production partially offset by increased interest expense. This is the result of the significant upfront capital costs associated with the Two Rivers East development project which commenced production in June 2025.

Cash flow from operating activities increased for the three months ended March 31, 2026 to \$7.8 million (\$0.01 per basic and diluted share) from \$1.2 million (\$nil per basic and diluted share) for the comparative period in 2025. Cash flow from operating activities differs from adjusted funds flow (used) due to the inclusion of changes in non-cash working capital and expenditures on decommissioning obligations.

## NET INCOME (LOSS)

The Company earned net income of \$3.8 million (\$0.01 per basic and diluted share) for the three months ended March 31, 2026, compared to a net loss incurred of \$3.6 million (\$0.01 per basic and diluted share) for the comparative period in 2025 mainly as 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

(\$000s)	Three Months Ended		
	March 31		
	2026	2025	% Change
Land	260	200	30
Drilling, completions, and workovers	3,865	343	1,027
Equipment	2,240	25,101	(91)
Geological and geophysical	439	57	670
Total expenditures	6,804	25,701	(74)

During the three months ended March 31, 2026, the Company finalized work at the Two Rivers East facility providing additional capacity and continued the completions and start-up of three Lower Montney wells at Two Rivers East which were placed on production late in Q1 2026.

During the three months ended March 31, 2025, the Company continued with facility procurement at Two Rivers East. Commercial production from Two Rivers East commenced in June 2025.

## LIQUIDITY AND CAPITAL RESOURCES

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

(\$000s)	March 31, 2026	December 31, 2025	% Change
Current assets	9,842	6,119	61
Less:			
Current liabilities	(33,517)	(48,635)	(31)
Working capital deficiency	(23,675)	(42,516)	(44)
Add:			
Current portion of other obligations	4,146	4,037	3
Current portion of decommissioning obligations	546	545	-
Adjusted working capital deficiency (Capital management measure)	(18,983)	(37,934)	(50)
Credit facility, non-current	(54,791)	(38,101)	44
Net debt (Capital management measure)	(73,774)	(76,035)	(3)

To facilitate its capital expenditure program, the Company had an \$80.0 million credit facility. At March 31, 2026, the Company had an adjusted working capital deficiency of \$19.0 million, which includes \$20.0 million drawn under its credit facility, and net debt of \$73.8 million which includes \$75.4 million drawn under its credit facility.

Average Q1 2026 production was 6,406 boe/d and exit Q1 2026 production was approximately 8,000 boe/d with the ramp up of new wells on production at Two Rivers East. This increase in production will help in reducing the adjusted working capital deficiency and net debt in 2026.

As at March 31, 2026, the Company had an \$80.0 million credit facility consisting of a \$10.0 million operating facility, a \$50.0 million syndicated facility, and a \$20.0 million term facility. The operating and syndicated facilities revolved for a 364 day period and were subject to an extension by May 31, 2026. If not extended, all outstanding advances would become repayable in one year (May 31, 2027). The term facility had a maturity date of May 31, 2026 and, therefore, has been presented as a current liability on the statement of financial position.

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

The credit facility included a covenant requiring the Company to maintain an adjusted working capital ratio of not less than one-to-one. The adjusted working capital ratio, as defined in the agreement, was calculated as current assets plus any undrawn amounts available on the credit facility less current liabilities excluding amounts drawn on the credit facility. The definition of current assets and current liabilities excludes the fair value of risk management contracts and amounts associated with the pipeline obligation. The Company was compliant with this covenant at March 31, 2026.

Subsequent to March 31, 2026, the Company completed the semi-annual review of the borrowing base with its lender resulting in a redetermined borrowing base of \$90.0 million, reflecting an increase in the syndicated facility from \$50.0 million to \$80.0 million and the cancellation of the \$20.0 million term facility. The amended credit facility agreement also extended the maturity date for an additional year to May 30, 2028 and removed the adjusted working capital ratio covenant. The next scheduled borrowing base review of the credit facility is scheduled on or before November 30, 2026.

As at March 31, 2026, the Company has a standby letter of credit facility agreement with a third party of up to \$10.0 million USD (\$13.9 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 March 31, 2026, the Company has \$11.8 million of standby letters of credit used against this facility (December 31, 2025 - \$10.1 million).

Subsequent to March 31, 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 will be repaid over a five-year period at an interest rate of 12.0%.

## CONTRACTUAL OBLIGATIONS

The following is a summary of the Company's contractual obligations and commitments at March 31, 2026:

(\$000s)	Total	Less than One Year	One to Three Years	After Three Years
Accounts payable and accrued liabilities	8,915	8,915	-	-
Credit facility - principal	75,404	20,000	55,404	-
Other obligations - principal	20,978	4,146	9,809	7,023
Decommissioning obligations	9,747	546	484	8,717
Operating commitments	1,558	272	594	692
Firm transportation agreements	173,220	6,541	18,645	148,034
Firm processing agreements	120,418	10,978	24,119	85,321
<b>Total contractual obligations</b>	<b>410,240</b>	<b>51,398</b>	<b>109,055</b>	<b>249,787</b>

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, 2026.

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

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

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

#### OFF BALANCE SHEET ARRANGEMENTS

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

#### 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)	March 31, 2026	May 26, 2026
Voting common shares	536,104	633,665
Warrants	29,377	29,377
Stock options	30,171	30,171
Restricted share units	9,053	9,053
Total	604,705	702,266

#### SUMMARY OF QUARTERLY RESULTS

	Q1 2026	Q4 2025	Q3 2025	Q2 2025	Q1 2025	Q4 2024	Q3 2024	Q2 2024
Average Daily Production								
Oil and NGLs (bbls/d)	2,208	1,316	1,464	566	209	502	254	323
Natural gas (mcf/d)	25,187	16,268	10,896	3,861	3,311	3,490	3,450	3,724
Oil equivalent (boe/d)	6,406	4,027	3,280	1,210	761	1,084	829	944
(\$000s, except per share amounts)								
Oil and natural gas sales	22,163	11,603	11,372	4,828	2,666	4,544	2,362	3,164
Cash flow from (used in)								
operating activities	7,758	4,852	4,712	(1,826)	1,168	3,157	(3,730)	(480)
Per share basic and diluted <sup>(2)</sup>	0.01	0.01	0.01	(-)	-	0.01	(0.01)	(-)
Adjusted funds flow (used) <sup>(1)</sup>								
Per share basic and diluted	10,319	2,310	2,386	(600)	(1,253)	382	(207)	262
Per share basic and diluted	0.02	-	-	(-)	(-)	-	(-)	-
Net income (loss)								
Per share basic and diluted	3,840	(2,181)	(1,764)	(3,464)	(3,617)	(2,903)	(2,464)	(2,329)
Per share basic and diluted	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 Operating Activities and Adjusted Funds Flow (Used)" section for a reconciliation from cash flow from operating activities.

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

The increase in production, oil and natural gas sales, cash flow from operating activities, and adjusted funds flow in the first quarter 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 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 March 31, 2026 was \$75.4 million (December 31, 2025 - \$58.8 million). A 100 basis point increase or decrease in interest rates would have impacted net income by approximately \$0.2 million for the three months ended March 31, 2026 (March 31, 2025 - \$69 thousand).

### *Commodity price risk*

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

At March 31, 2026, the Company had the following physical commodity price contracts outstanding:

<b>Commodity</b>	<b>Period</b>	<b>Type of Contract</b>	<b>Quantity</b>	<b>Contract Price</b>
Oil	April 1, 2026 - April 30, 2026	Physical Sales	500 bbls/d	WTI CDN \$86.86/bbl
Oil	May 1, 2026 - June 30, 2026	Physical Sales	500 bbls/d	WTI CDN \$85.69/bbl

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

### *Credit risk*

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

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

The maximum exposure to credit risk is represented by the carrying amount of accounts receivable on the statement of financial position. At March 31, 2026, \$9.5 million (>99%) of the Company's outstanding accounts receivable were current and \$5 thousand (<1%) were outstanding for more than 90 days. During the three months ended March 31, 2026, the Company deemed \$nil of outstanding accounts receivable to be uncollectable (March 31, 2025 - \$3 thousand).

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 had an \$80.0 million credit facility (refer to the "Liquidity and Capital Resources" section). At March 31, 2026, the Company had an adjusted working capital deficiency of \$19.0 million, which includes \$20.0 million drawn under its credit facility, and net debt of \$73.8 million which includes \$75.4 million drawn under its credit facility.

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

Subsequent to March 31, 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 Two Rivers East development project, the resultant production from the 5-19 pad, the expanded credit facility, and the proceeds from the bought-deal financing, the Company anticipates that it will have sufficient lending capacity and operational cash flows to meet its current and future obligations, to make any scheduled credit facility and associated interest payments, and to fund the other needs of the business for at least the next 12 months. Coelacanth's capital program is flexible and can be adjusted as needed based upon the current economic environment. The Company will continue to monitor the economic environment and the possible impact on its business and strategy and will make adjustments as necessary.

## 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](http://www.sedarplus.com).

## PRODUCT TYPES

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

**Natural gas** refers to shale gas.

**Oil and condensate** refers to condensate and tight oil combined.

**Other NGLs** refers to butane, propane and ethane combined.

**Oil and NGLs** refers to tight oil and NGLs combined.

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

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

Sales Volumes by Product Type	Q1 2026	Q4 2025	Q3 2025	Q2 2025	Q1 2025	Q4 2024	Q3 2024	Q2 2024
Condensate (bbls/d)	166	109	46	17	18	22	33	56
Other NGLs (bbls/d)	301	165	92	27	25	29	33	39
NGLs (bbls/d)	467	274	138	44	43	51	66	95
Tight oil (bbls/d)	1,741	1,042	1,326	522	166	451	188	228
Condensate (bbls/d)	166	109	46	17	18	22	33	56
Oil and condensate (bbls/d)	1,907	1,151	1,372	539	184	473	221	284
Other NGLs (bbls/d)	301	165	92	27	25	29	33	39
Oil and NGLs (bbls/d)	2,208	1,316	1,464	566	209	502	254	323
Shale gas (mcf/d)	25,187	16,268	10,896	3,861	3,311	3,490	3,450	3,724
Natural gas (mcf/d)	25,187	16,268	10,896	3,861	3,311	3,490	3,450	3,724
Oil equivalent (boe/d)	6,406	4,027	3,280	1,210	761	1,084	829	944

## 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, adjusted working capital deficiency, and net 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 4 identified Montney zones. See news release dated August 27, 2025 for more details.

Total Petroleum Initially-In-Place 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](http://www.sedarplus.com).

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

(\$000s)	Note	March 31 2026	December 31 2025
<b>Assets</b>			
Current assets			
Accounts receivable		9,514	5,645
Prepaid expenses and deposits		328	474
		<b>9,842</b>	<b>6,119</b>
Property, plant, and equipment	(4)	243,126	241,632
Exploration and evaluation assets	(5)	28,780	28,049
		<b>271,906</b>	<b>269,681</b>
		<b>281,748</b>	<b>275,800</b>
<b>Liabilities</b>			
Current liabilities			
Credit facility	(7)	19,910	19,775
Accounts payable and accrued liabilities		8,915	24,278
Current portion of other obligations	(6)	4,146	4,037
Current portion of decommissioning obligations	(8)	546	545
		<b>33,517</b>	<b>48,635</b>
Credit facility	(7)	54,791	38,101
Other obligations	(6)	16,832	17,912
Decommissioning obligations	(8)	9,201	9,050
		<b>114,341</b>	<b>113,698</b>
<b>Shareholders' Equity</b>			
Shareholders' capital	(9)	179,414	177,319
Warrants	(9)	5,015	5,015
Contributed surplus		11,558	12,188
Deficit		(28,580)	(32,420)
		<b>167,407</b>	<b>162,102</b>
		<b>281,748</b>	<b>275,800</b>
Commitments	(16)		
Subsequent events	(7,9,16)		

*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)

**Three Months Ended**  
**March 31**

(\$000s, except per share amounts)	Note	2026	2025
<b>Revenue</b>			
Oil and natural gas sales	(15)	22,163	2,666
Royalties		(2,087)	(491)
		<b>20,076</b>	<b>2,175</b>
<b>Expenses</b>			
Operating		4,493	728
Transportation		1,633	551
Depletion and depreciation	(4)	4,898	979
General and administrative		1,643	1,489
Share based compensation	(10)	1,231	1,264
Finance income		-	(100)
Finance expense		2,338	881
		<b>16,236</b>	<b>5,792</b>
<b>Net income (loss) and comprehensive income (loss)</b>		<b>3,840</b>	<b>(3,617)</b>
Net income (loss) per share			
Basic and diluted	(11)	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		-	-	-	(3,617)	(3,617)
Settlement of vested RSUs	(9)	1,195	-	(1,195)	-	-
Settlement of stock options	(10)	-	-	(104)	-	(104)
Share based compensation	(10)	-	-	1,454	-	1,454
Balance, March 31, 2025		176,502	6,979	7,292	(25,011)	165,762
Balance, December 31, 2025		<b>177,319</b>	<b>5,015</b>	<b>12,188</b>	<b>(32,420)</b>	<b>162,102</b>
Net income		-	-	-	<b>3,840</b>	<b>3,840</b>
Settlement of vested RSUs	(9)	<b>2,095</b>	-	<b>(2,095)</b>	-	-
Share based compensation	(10)	-	-	<b>1,465</b>	-	<b>1,465</b>
Balance, March 31, 2026		<b>179,414</b>	<b>5,015</b>	<b>11,558</b>	<b>(28,580)</b>	<b>167,407</b>

*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

March 31

(\$000s)	Note	2026	2025
<b>Operating Activities</b>			
Net income (loss)		3,840	(3,617)
Depletion and depreciation	(4)	4,898	979
Share based compensation	(10)	1,231	1,264
Finance expense		2,338	881
Interest paid		(1,988)	(422)
Financing obligation payments	(7)	-	(338)
Decommissioning expenditures	(8)	(18)	(139)
Change in non-cash working capital	(14)	(2,543)	2,560
		<b>7,758</b>	<b>1,168</b>
<b>Financing Activities</b>			
Credit facility	(7)	16,560	15,000
Proceeds from other obligations	(6)	-	22,658
Payment of other obligations	(6)	(971)	(27)
Settlement of stock options	(10)	-	(104)
		<b>15,589</b>	<b>37,527</b>
<b>Investing Activities</b>			
Capital expenditures - property, plant, and equipment	(4)	(6,096)	(668)
Capital expenditures - exploration and evaluation assets	(5)	(708)	(25,033)
Change in non-cash working capital	(14)	(16,543)	(17,619)
		<b>(23,347)</b>	<b>(43,320)</b>
Change in cash		-	(4,625)
Cash, beginning of period		-	5,693
Cash, end of period		-	1,068

*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 May 26, 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

<b>Cost</b>	<b>Total</b>
Balance, December 31, 2025	303,849
Additions	<b>6,096</b>
Capitalized share based compensation	<b>211</b>
Change in decommissioning obligation estimates (note 8)	<b>85</b>
<b>Balance, March 31, 2026</b>	<b>310,241</b>
<b>Accumulated Depletion, Depreciation, and Impairment</b>	
Balance, December 31, 2025	62,217
Depletion and depreciation	<b>4,898</b>
<b>Balance, March 31, 2026</b>	<b>67,115</b>
<b>Net Book Value</b>	
December 31, 2025	241,632
<b>March 31, 2026</b>	<b>243,126</b>

During the three months ended March 31, 2026, approximately \$65 thousand (March 31, 2025 - \$9 thousand) 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 March 31, 2026 included an estimated \$112.3 million (March 31, 2025 - \$21.4 million) for forecasted future development costs associated with proved and probable undeveloped oil and natural gas reserves and excluded approximately \$7.0 million (March 31, 2025 - \$1.0 million) for the estimated salvage value of production equipment and facilities. Depletion expense on development and production assets was \$4.3 million for the three months ended March 31, 2026 (March 31, 2025 - \$0.9 million). At March 31, 2026, \$10.1 million of assets under construction were excluded from the depreciation calculation (March 31, 2025 - \$nil).

Included in depletion and depreciation expense for the three months ended March 31, 2026, is \$32 thousand (March 31, 2025 - \$22 thousand) related to the Company's right-of-use assets. At March 31, 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 March 31, 2026 for its PP&E Two Rivers CGU and no impairment test was required to be performed.

#### 5. EXPLORATION AND EVALUATION ASSETS

	<b>Total</b>
Balance, December 31, 2025	28,049
Additions	<b>708</b>
Capitalized share based compensation	<b>23</b>
<b>Balance, March 31, 2026</b>	<b>28,780</b>

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

During the three months ended March 31, 2026, approximately \$24 thousand (March 31, 2025 - \$0.1 million) of directly attributable general and administrative costs were capitalized as expenditures on E&E assets.

At March 31, 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	(1,509)	(39)	(1,548)
Interest expense	559	18	577
<b>Balance, March 31, 2026</b>	<b>20,203</b>	<b>775</b>	<b>20,978</b>
Current	4,062	84	4,146
Long-term	16,141	691	16,832
	<b>20,203</b>	<b>775</b>	<b>20,978</b>

### Pipeline obligation

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

### Lease obligations

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

	March 31, 2026
Within one year	154
Later than one year but not later than three years	369
Later than three years	484
Minimum lease payments	1,007
Amount representing interest expense	(232)
Present value of net lease and other obligation payments	<b>775</b>

## 7. CREDIT FACILITY

	Total
Balance, December 31, 2025	57,876
Net proceeds	16,560
Amortization of issuance costs	265
<b>Balance, March 31, 2026</b>	<b>74,701</b>
Current	19,910
Long-term	54,791
	<b>74,701</b>

As at March 31, 2026, the Company had an \$80.0 million credit facility consisting of a \$10.0 million operating facility, a \$50.0 million syndicated facility, and a \$20.0 million term facility. The operating and syndicated facilities revolved for a 364 day period and were subject to an extension by May 31, 2026. If not extended, all outstanding advances would become repayable in one year (May 31, 2027). The term facility had a maturity date of May 31, 2026 and, therefore, has been presented as a current liability on the statement of financial position.

Advances under the credit facility are available by way of prime rate loans, with interest rates between 2.00% and 4.00% over the Canadian prime lending rate and Canadian Overnight Repo Rate Average ("CORRA") loans which are subject to margins ranging from

3.00% to 5.00% depending upon the debt to EBITDA ratio of the Company as defined in the agreement. Standby fees are charged on the undrawn portion of the credit facility at rates ranging from 0.75% to 1.25%. Until delivery of the Q1 2026 compliance certificate, the prime rate margin is fixed at 3.0%, the CORRA margin is fixed at 4.0% and standby fees are fixed at 1.0%. The term facility margins were based on the applicable margins for the operating and syndicated facilities plus 2.5% and must be drawn first before the operating and syndicated facilities. The credit facility is secured by a \$250.0 million fixed and floating charge debenture on the assets of the Company.

The credit facility included a covenant requiring the Company to maintain an adjusted working capital ratio of not less than one-to-one. The adjusted working capital ratio, as defined in the agreement, was calculated as current assets plus any undrawn amounts available on the credit facility less current liabilities excluding amounts drawn on the credit facility. The definition of current assets and current liabilities excludes the fair value of risk management contracts and amounts associated with the pipeline obligation (note 6). The Company was compliant with this covenant at March 31, 2026.

Subsequent to March 31, 2026, the Company completed the semi-annual review of the borrowing base with its lender resulting in a redetermined borrowing base of \$90.0 million, reflecting an increase in the syndicated facility from \$50.0 million to \$80.0 million and the cancellation of the \$20.0 million term facility. The amended credit facility agreement also extended the maturity date for an additional year to May 30, 2028 and removed the adjusted working capital ratio covenant. The next scheduled borrowing base review of the credit facility is scheduled on or before November 30, 2026.

As at March 31, 2026, the Company has a standby letter of credit facility agreement with a third party of up to \$10.0 million USD (\$13.9 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 March 31, 2026, the Company has \$11.8 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. These estimates were made by management using information obtained from government estimates and internal analysis assuming current costs, technology and enacted legislation. The total undiscounted amount of the estimated cash flows, adjusted for inflation at 1.98% per year (December 31, 2025 - 1.93%) required to settle the decommissioning obligations is approximately \$18.5 million (December 31, 2025 - \$18.3 million) which is estimated to be incurred over the next 32 years. At March 31, 2026, a risk-free rate of 3.81% (December 31, 2025 - 3.80%) was used to calculate the net present value of the decommissioning obligations.

	Three Months Ended March 31, 2026	Year Ended December 31, 2025
Balance, beginning of period	9,595	9,649
Provisions incurred	-	675
Provisions settled	(18)	(421)
Revisions in estimated cash flows	-	(201)
Revisions due to change of rates	85	(395)
Accretion	85	288
<b>Balance, end of period</b>	<b>9,747</b>	<b>9,595</b>
Current	546	545
Long-term	9,201	9,050
	<b>9,747</b>	<b>9,595</b>

## 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
Settlement of vested restricted share units	2,639	2,095
<b>Balance, March 31, 2026</b>	<b>536,104</b>	<b>179,414</b>
<b>Warrants</b>	<b>Number</b>	<b>Amount</b>
<b>Balance, December 31, 2025 and March 31, 2026</b>	<b>29,377</b>	<b>5,015</b>

The following table summarizes the warrants outstanding and exercisable at March 31, 2026:

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

Subsequent to March 31, 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.

## 10. SHARE BASED COMPENSATION PLANS

### Stock options

The Company has authorized and reserved for issuance 53.6 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 March 31, 2026, 30.2 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
Forfeited	(50)	0.80
<b>Balance, March 31, 2026</b>	<b>30,171</b>	<b>0.76</b>
<b>Exercisable, March 31, 2026</b>	<b>15,067</b>	<b>0.72</b>

The following table summarizes the stock options outstanding and exercisable at March 31, 2026:

Exercise Price	Options Outstanding			Options Exercisable	
	Number	Weighted Average Remaining Life (years)	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
\$0.54 to \$0.70	4,078	1.5	0.56	3,862	0.55
\$0.71 to \$0.79	4,326	1.8	0.75	4,326	0.75
\$0.80 to \$0.83	21,767	3.9	0.80	6,879	0.80
	30,171	3.2	0.76	15,067	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:

	March 31, 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 months ended March 31, 2026, the Company recognized \$0.6 million (March 31, 2025 - \$0.7 million) of share based compensation related to the stock options of which \$0.5 million was recognized as an expense and \$95 thousand was capitalized (March 31, 2025 - \$0.6 million was recognized as an expense and \$88 thousand was capitalized). At March 31, 2026, there was \$2.9 million remaining as unrecognized share based compensation related to the stock options.

During the three months ended March 31, 2026, the Company settled nil stock options (March 31, 2025 - 0.3 million stock options for a \$104 thousand cash payment).

### 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.

	<b>Number of RSUs</b>
Balance, December 31, 2025	6,348
Granted	<b>5,369</b>
Exercised	<b>(2,639)</b>
Forfeited	<b>(25)</b>
<b>Balance, March 31, 2026</b>	<b>9,053</b>
<b>Exercisable, March 31, 2026</b>	-

The weighted average market price of the Company's common shares used to value the RSUs granted during the three months ended March 31, 2026 was \$0.80 (March 31, 2025 - \$0.81). During the three months ended March 31, 2026, the Company recognized \$0.9 million (March 31, 2025 - \$0.8 million) of share based compensation related to the RSUs of which \$0.7 million was recognized as an expense and \$0.2 million was capitalized (March 31, 2025 - \$0.7 million was recognized as an expense and \$0.1 million was capitalized). At March 31, 2026, there was \$5.1 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 settled as to one-third on each of the first, second and third anniversaries of the date of grant multiplied by a payout multiplier ranging from 0 to 2.0 times and is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period. For the purpose of calculating share based compensation, the fair value of each award is determined at the grant date using the closing price of the Company's common shares. On the date of exercise, the Company has the option of settling the award value in cash, common shares of the Company, or a combination thereof.

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

#### **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:

	<b>Three Months Ended March 31</b>	
	<b>2026</b>	2025
Weighted average number of shares - basic	<b>535,151</b>	531,445
Dilutive effect of share based compensation plans and warrants	<b>23,052</b>	-
Weighted average number of shares - diluted	<b>558,203</b>	531,445

For the three months ended March 31, 2026, 19.4 million stock options (March 31, 2025 - 22.4 million), nil RSUs (March 31, 2025 - 7.6 million), and nil warrants (March 31, 2025 - 62.7 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 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 March 31, 2026 was \$75.4 million (December 31, 2025 - \$58.8 million). A 100 basis point increase or decrease in interest rates would have impacted net income by approximately \$0.2 million for the three months ended March 31, 2026 (March 31, 2025 - \$69 thousand).

#### *Commodity price risk*

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

At March 31, 2026, the Company had the following physical commodity price contracts outstanding:

<b>Commodity</b>	<b>Period</b>	<b>Type of Contract</b>	<b>Quantity</b>	<b>Contract Price</b>
Oil	April 1, 2026 - April 30, 2026	Physical Sales	500 bbls/d	WTI CDN \$86.86/bbl
Oil	May 1, 2026 - June 30, 2026	Physical Sales	500 bbls/d	WTI CDN \$85.69/bbl

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

#### **Credit risk**

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

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

The maximum exposure to credit risk is represented by the carrying amount of accounts receivable on the statement of financial position. At March 31, 2026, \$9.5 million (>99%) of the Company's outstanding accounts receivable were current and \$5 thousand (<1%) were outstanding for more than 90 days. During the three months ended March 31, 2026, the Company deemed \$nil of outstanding accounts receivable to be uncollectable (March 31, 2025 - \$3 thousand).

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 had an \$80.0 million credit facility (see note 7). At March 31, 2026, the Company had an adjusted working capital deficiency of \$19.0 million (see note 13), which includes \$20.0 million drawn under its credit facility, and net debt of \$73.8 million (see note 13) which includes \$75.4 million drawn under its credit facility.

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

Subsequent to March 31, 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 Two Rivers East development project, the resultant production from the 5-19 pad, the expanded credit facility, and the proceeds from the bought-deal financing, the Company anticipates that it will have sufficient lending capacity and operational cash flows to meet its current and future obligations, to make any scheduled credit facility and associated interest payments, and to fund the other needs of the business for at least the next 12 months. Coelacanth's capital program is flexible and can be adjusted as needed based upon the current economic environment. The Company will continue to monitor the economic environment and the possible impact on its business and strategy and will make adjustments as necessary.

The timing of undiscounted cash outflows relating to the Company's financial liabilities at March 31, 2026 is outlined in the table below. It is not expected that the cash flows included in the maturity analysis could occur significantly earlier or at significantly different amounts, with the exception of a future breach of a covenant under the credit facility that would require repayment earlier than indicated. Interest on the credit facility has been excluded as interest payments fluctuate based on amounts outstanding and the prevailing interest rate at the time of borrowing.

	2026	2027	2028	2029	2030	Total
Accounts payable and accrued liabilities	8,915	-	-	-	-	8,915
Credit facility - principal <sup>(1)</sup>	20,000	55,404	-	-	-	75,404
Pipeline obligation (note 6)	4,527	6,035	6,035	6,035	2,518	25,150
<b>Total</b>	<b>33,442</b>	<b>61,439</b>	<b>6,035</b>	<b>6,035</b>	<b>2,518</b>	<b>109,469</b>

(1) Subsequent to March 31, 2026, the \$20.0 million term facility due May 31, 2026 was cancelled and replaced by an increase in the syndicated facility and the maturity date of the credit facility was extended to May 30, 2028 (see note 7).

See note 6 for a maturity analysis of the Company's lease obligations and note 16 for a summary of contractual commitments at March 31, 2026.

### 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 debt. Adjusted working capital deficiency includes current assets less current liabilities, excluding the current portion of decommissioning obligations and other obligations. Net debt includes adjusted working capital deficiency and non-current portion of the credit facility. To maintain or adjust the capital structure, the Company may, from time to time, issue shares, raise debt, or adjust its capital spending to manage its current and projected debt levels.

	March 31, 2026	December 31, 2025
Shareholders' equity	167,407	162,102
Net debt	(73,774)	(76,035)

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

(\$000s)	March 31, 2026	December 31, 2025
Current assets	9,842	6,119
Less:		
Current liabilities	(33,517)	(48,635)
Working capital deficiency	(23,675)	(42,516)
Add:		
Current portion of other obligations	4,146	4,037
Current portion of decommissioning obligations	546	545
Adjusted working capital deficiency	(18,983)	(37,934)
Credit facility, non-current	(54,791)	(38,101)
Net debt	(73,774)	(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, however, the Company's credit facility includes a covenant requiring the Company to maintain an adjusted working capital ratio of not less than one-to-one. This covenant was subsequently removed under the amended credit facility (see note 7).

#### 14. SUPPLEMENTAL CASH FLOW INFORMATION

	March 31, 2026	March 31, 2025
Accounts receivable	(3,869)	2,716
Prepaid expenses and deposits <sup>(1)</sup>	146	111
Accounts payable and accrued liabilities	(15,363)	(17,886)
Change in non-cash working capital	(19,086)	(15,059)
Relating to:		
Operating	(2,543)	2,560
Investing	(16,543)	(17,619)
Change in non-cash working capital	(19,086)	(15,059)

(1) For the three months ended March 31, 2026, excludes \$nil (March 31, 2025 - \$0.7 million) of debt issuance costs that were re-classified as a reduction to the revolving credit facility balance when the facility was drawn on.

#### 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 sales disaggregated by revenue source:

	Three Months Ended March 31	
	2026	2025
Oil and condensate	15,099	1,495
Other natural gas liquids	698	85
Natural gas	6,366	1,086
Total revenue	22,163	2,666

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 March 31	
	2026	2025
Natural gas production sales	5,470	858
Transportation revenue	896	228
Natural gas sales	6,366	1,086

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 92% for the three months ended March 31, 2026 (March 31, 2025 - two customers represented combined sales of 90%).

#### 16. COMMITMENTS

The following is a summary of the Company's contractual obligations and commitments at March 31, 2026:

	2026	2027	2028	2029	2030	Thereafter	Total
Operating commitments	197	297	297	297	297	173	1,558
Firm transportation agreements	4,580	7,809	9,912	11,540	11,540	127,839	173,220
Firm processing agreements	8,008	11,881	12,118	12,360	12,608	63,443	120,418
	12,785	19,987	22,327	24,197	24,445	191,455	295,196

Operating commitments include the non-lease variable components (operating expenses) of the head office lease (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, 2026.

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

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

Firm processing agreements include 30.0 mmcf/d of processing services at a gas processing facility for a period of 10 years. Effective July 1, 2026, the commitment increases to 40.0 mmcf/d for the remaining term. Under the terms of the processing agreement, the Company can elect prior to November 1, 2026 to increase by any volume up to an additional 20.0 mmcf/d (60.0 mmcf/d total) for the remainder of the original term. As part of the arrangement, the midstream company funded the extension of their gathering system (see note 6).

# CORPORATE INFORMATION

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**Bill Lancaster P.Geo.**  
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**John A. Brussa, B.A., LL.B.**  
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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).