Q1 2025 RESULTS

FINANCIAL AND OPERATING RESULTS FOR THE THREE MONTHS ENDED MARCH 31, 2025

COELACANTH ENERGY INC.

FINANCIAL RESULTS	THREE MONTHS ENDED MARCH 31		
($000s, except per share amounts)	2025	2024	% Change
OIL AND NATURAL GAS SALES	**2,666**	3,666	(27)
CASH FLOW FROM OPERATING ACTIVITIES	**981**	3,256	(70)
Per share - basic and diluted [3]	**-**	0.01	(100)
ADJUSTED FUNDS FLOW (USED)[1]	**(1,440)**	1,078	(234)
Per share - basic and diluted	**(-)**	-	(-)
NET LOSS	**(3,617)**	(1,201)	201
Per share - basic and diluted	**(0.01)**	(-)	100
CAPITAL EXPENDITURES [4]	**25,701**	1,263	1,935
ADJUSTED WORKING CAPITAL (DEFICIENCY) [2]	**(25,710)**	67,139	(138)
COMMON SHARES OUTSTANDING (000s)			
Weighted average - basic and diluted	**531,445**	529,196	-
End of period - basic	**532,202**	529,392	1
End of period - fully diluted	**624,877**	618,165	1

(1) 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.

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

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

(4) 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.

OPERATING RESULTS [1]	Three Months Ended March 31		
	2025	2024	% Change
Daily production [2]			
Oil and condensate (bbls/d)	**184**	300	(39)
Other NGLs (bbls/d)	**25**	37	(32)
Oil and NGLs (bbls/d)	**209**	337	(38)
Natural gas (mcf/d)	**3,311**	3,934	(16)
Oil equivalent (boe/d)	**761**	993	(23)
Oil and natural gas sales			
Oil and condensate ($/bbl)	**90.21**	85.30	6
Other NGLs ($/bbl)	**38.01**	34.79	9
Oil and NGLs ($/bbl)	**84.03**	79.82	5
Natural gas ($/mcf)	**3.65**	3.40	7
Oil equivalent ($/boe)	**38.94**	40.57	(4)
Royalties			
Oil and NGLs ($/bbl)	**15.95**	20.77	(23)
Natural gas ($/mcf)	**0.64**	0.51	25
Oil equivalent ($/boe)	**7.18**	9.08	(21)
Operating expenses			
Oil and NGLs ($/bbl)	**10.63**	9.89	7
Natural gas ($/mcf)	**1.77**	1.65	7
Oil equivalent ($/boe)	**10.63**	9.89	7
Net transportation expenses [3]			
Oil and NGLs ($/bbl)	**2.27**	2.45	(7)
Natural gas ($/mcf)	**0.78**	0.68	15
Oil equivalent ($/boe)	**4.00**	3.54	13
Operating netback [4]			
Oil and NGLs ($/bbl)	**55.18**	46.71	18
Natural gas ($/mcf)	**0.46**	0.56	(18)
Oil equivalent ($/boe)	**17.13**	18.06	(5)
Depletion and depreciation ($/boe)	**(14.30)**	(14.42)	(1)
General and administrative expenses ($/boe)	**(21.76)**	(13.86)	57
Share based compensation ($/boe)	**(18.46)**	(10.11)	83
Finance expense ($/boe)	**(12.86)**	(1.06)	1,113
Finance income ($/boe)	**1.46**	10.60	(86)
Unutilized transportation ($/boe)	**(4.05)**	(2.49)	63
Net loss ($/boe)	**(52.84)**	(13.28)	298

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

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

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

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

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

May 28, 2025

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

DESCRIPTION OF BUSINESS

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

OIL AND GAS TERMS

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

Liquids

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

Natural Gas

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

Oil Equivalent

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

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

NOTE REGARDING PRODUCT TYPES

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

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

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

NON-GAAP AND OTHER FINANCIAL MEASURES

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

Non-GAAP Financial Measures

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

decommissioning obligations. Management believes the timing of collection, payment or incurrence of these items involves a high degree of discretion and as such may not be useful for evaluating the Company's cash flows. Adjusted funds flow (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)	**2025**	2024
Transportation expenses	**551**	545
Unutilized transportation	**(277)**	(225)
Net transportation expenses (non-GAAP)	**274**	320

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)	**2025**	2024
Oil and natural gas sales	**2,666**	3,666
Royalties	**(491)**	(821)
Operating expenses	**(728)**	(894)
Net transportation expenses	**(274)**	(320)
Operating netback (non-GAAP)	**1,173**	1,631

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)	**2025**	2024
Capital expenditures – property, plant, and equipment	**668**	393
Capital expenditures – exploration and evaluation assets	**25,033**	870
Capital expenditures (non-GAAP)	**25,701**	1,263

Capital Management Measures

Adjusted working capital (deficiency)
Management uses adjusted working capital (deficiency) as a measure to assess the Company's financial position. Adjusted working capital (deficiency) is calculated as current assets and restricted cash deposits less current liabilities, excluding the current portion of decommissioning obligations. Refer to the calculation of adjusted working capital (deficiency) and reconciliation to working capital 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 loss per share.

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

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

Supplementary Financial Measures

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

OPERATIONS UPDATE

Coelacanth has reached a major milestone in its development with the completion of the Two Rivers East facility (the "Facility"). The Facility was completed on budget and has moved to the testing and start-up phase. The capacity of the Facility is currently 8,000 boe/d but will be expanded in Q4 2025 to 16,000 boe/d with added compression. We expect production to start flowing imminently from the 5-19 pad and ramp up through the summer. As previously released, the 5-19 pad has 9 wells that tested over 11,000 boe/d [(1)] that will be brought on systematically to approach the phase I capacity of the plant prior to further drilling.

Over the next few years, Coelacanth will continue with its business plan that incorporates:

(1) Systematically developing the resource using pad development and horizontal multi-frac technology to increase production and maximize cash flow and investment returns.
(2) Delineating the lands with vertical and horizontal wells to help in quantifying and understanding the commerciality of its large Montney resource base that includes up to four Montney benches over its 150 contiguous sections of land.
(3) Developing and licensing a flexible infrastructure plan that will allow for the resource to be scaled to a much larger production base.

Coelacanth has licensed additional locations on the 5-19 pad, is in the process of licensing additional development pads, delineation locations and additional infrastructure to grow beyond current plant capacity. While commodity prices and available capital will dictate the pace of execution of the business plan, we are very pleased with the results to date and look forward to reporting on new developments as they arise.

(1) See "Test Results and Initial Production Rates" section for more details.

SUMMARY OF FINANCIAL RESULTS

	Three Months Ended March 31		
($000s, except per share amounts)	**2025**	2024	% Change
Oil and natural gas sales	**2,666**	3,666	(27)
Cash flow from operating activities	**981**	3,256	(70)
Per share - basic and diluted [(3)]	**-**	0.01	(100)
Adjusted funds flow (used) [(1)]	**(1,440)**	1,078	(234)
Per share - basic and diluted	**(-)**	-	(-)
Net loss	**(3,617)**	(1,201)	201
Per share - basic and diluted	**(0.01)**	(-)	100
Total assets	**229,997**	186,003	24
Total long-term liabilities	**28,226**	7,604	271
Adjusted working capital (deficiency) [(2)]	**(25,710)**	67,139	(138)

(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 and restricted cash deposits less current liabilities, excluding the current portion of decommissioning obligations. Please refer to the "Non-GAAP and Other Financial Measures" section for more details.

(3) 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, and adjusted funds flow decreased and net loss increased in Q1 2025 compared to Q1 2024 due to a decrease in oil and natural gas production stemming from natural declines.

PRODUCTION

	Three Months Ended March 31		
	2025	2024	% Change
Average Daily Production (1)			
Oil and condensate (bbls/d)	**184**	300	(39)
Other NGLs (bbls/d)	**25**	37	(32)
Oil and NGLs (bbls/d)	**209**	337	(38)
Natural gas (mcf/d)	**3,311**	3,934	(16)
Oil equivalent (boe/d)	**761**	993	(23)

(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 decreased to 761 boe/d for the three months ended March 31, 2025 from 993 boe/d for the comparative period in 2024 due to natural declines. Commercial production at Two Rivers East is expected to start with the completion of the facility in June 2025.

Coelacanth's production profile for the first quarter of 2025 shifted more towards natural gas when compared to the comparative quarter in 2024 as the result of flush oil production in Q1 2024 from Two Rivers West declining during the past 12 months. The Q1 2025 weighting was 73% natural gas (Q1 2024 - 66%) and 27% oil and NGLs (Q1 2024 - 34%).

OIL AND NATURAL GAS SALES

	Three Months Ended March 31		
($000s)	**2025**	2024	% Change
Oil and condensate	**1,495**	2,334	(36)
Other NGLs	**85**	116	(27)
Oil and NGLs	**1,580**	2,450	(36)
Natural gas	**1,086**	1,216	(11)
Total	**2,666**	3,666	(27)
Average Sales Price			
Oil and condensate ($/bbl)	**90.21**	85.30	6
Other NGLs ($/bbl)	**38.01**	34.79	9
Oil and NGLs ($/bbl)	**84.03**	79.82	5
Natural gas production sales and transportation revenue ($/mcf)	**3.65**	3.40	7
Combined ($/boe)	**38.94**	40.57	(4)

Revenue totaled $2.7 million for the three months ended March 31, 2025, down from $3.7 million for the comparative period in 2024 mainly as a result of a decrease in production stemming from natural declines.

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

Commodity Pricing

	Three Months Ended March 31		
	2025	2024	% Change
Oil and NGLs			
Corporate price ($CDN/bbl)	**84.03**	79.82	5
Canadian light sweet ($CDN/bbl)	**94.99**	95.45	(-)
West Texas Intermediate ("WTI") ($US/bbl)	**71.42**	76.96	(7)
Natural gas			
Corporate price ($CDN/mcf)	**3.65**	3.40	7
AECO price ($CDN/mcf)	**2.13**	2.18	(2)
Westcoast Station 2 ($CDN/mcf)	**1.22**	2.11	(42)
Chicago City Gate ($US/mmbtu)	**4.02**	2.82	43
Exchange rate			
CDN/US dollar exchange rate	**0.6972**	0.7417	(6)

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 88.5% of Canadian light sweet prices for the three months ended March 31, 2025, consistent with 83.6% for the comparative period in 2024. Coelacanth's liquids mix during the first quarter of 2025 was approximately 88% light oil, condensate and pentanes, 5% butane and 7% propane (Q1 2024 - 89% light oil, condensate and pentanes, 5% butane and 6% propane).

Corporate average natural gas prices were 63.3% of Chicago City Gate price (converted to Canadian dollars) for the three months ended March 31, 2025, down from 89.4% for the comparative period in 2024. The decrease was mainly due to a 42% reduction in Westcoast Station 2 prices in Q1 2025 from Q1 2024. The Company has contracted 1.5 mmcf/d of natural gas to be delivered to Chicago with the remainder being delivered to Westcoast Station 2.

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

ROYALTIES	**Three Months Ended March 31**		
($000s)	**2025**	2024	% Change
Oil and NGLs	**300**	638	(53)
Natural gas	**191**	183	4
Royalties	**491**	821	(40)

Average Royalty Rate (% of sales)			
Oil and NGLs	**19.0**	26.0	(27)
Natural gas	**17.6**	15.0	17
Combined	**18.4**	22.4	(18)

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

Royalties totaled $0.5 million for the three months ended March 31, 2025, down from $0.8 million for the comparative period in 2024. The decrease in royalties and royalty rates is mainly the result of production declines.

OPERATING EXPENSES	**Three Months Ended March 31**		
($000s)	**2025**	2024	% Change
Oil and NGLs	**200**	304	(34)
Natural gas	**528**	590	(11)
Operating expenses	**728**	894	(19)

Average operating expenses			
Oil and NGLs ($/bbl)	**10.63**	9.89	7
Natural gas ($/mcf)	**1.77**	1.65	7
Combined ($/boe)	**10.63**	9.89	7

Per unit operating expenses were $10.63/boe for the three months ended March 31, 2025, consistent with $9.89/boe in the comparative period in 2024.

NET TRANSPORTATION EXPENSES	Three Months Ended March 31		
($000s)	**2025**	2024	% Change
Oil and NGLs	**43**	75	(43)
Natural gas	**231**	245	(6)
Net transportation expenses (non-GAAP)	**274**	320	(14)
Unutilized transportation	**277**	225	23
Transportation expenses	**551**	545	1
Average transportation expenses			
Oil and NGLs ($/bbl)	**2.27**	2.45	(7)
Natural gas ($/mcf)	**0.78**	0.68	15
Net transportation expenses ($/boe)	**4.00**	3.54	13
Unutilized transportation ($/boe)	**4.05**	2.49	63
Transportation expenses ($/boe)	**8.05**	6.03	33

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 were $0.6 million for the three months ended March 31, 2025, consistent with $0.6 million for the comparative period in 2024.

Net transportation expenses increased on a per boe basis to $4.00/boe for the three months ended March 31, 2025, compared to $3.54/boe for the comparative period in 2024. The increase is mainly the result of a larger percentage of natural gas being delivered to Chicago with a higher net transportation expense). While the sales prices were higher on Chicago contracts than on AECO and Westcoast Station 2 contracts, the net transportation expenses are also higher. 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.

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 “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 large 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 30.6 mmcf/d for April 1, 2025 through December 31, 2025.

OPERATING NETBACK	Three Months Ended March 31		
	2025	2024	% Change
Oil and NGLs ($/bbl)			
Revenue	**84.03**	79.82	5
Royalties	**(15.95)**	(20.77)	(23)
Operating expenses	**(10.63)**	(9.89)	7
Net transportation expenses (non-GAAP)	**(2.27)**	(2.45)	(7)
Operating netback (non-GAAP)	**55.18**	46.71	18
Natural gas ($/mcf)			
Revenue	**3.65**	3.40	7
Royalties	**(0.64)**	(0.51)	25
Operating expenses	**(1.77)**	(1.65)	7
Net transportation expenses (non-GAAP)	**(0.78)**	(0.68)	15
Operating netback (non-GAAP)	**0.46**	0.56	(18)
Combined ($/boe)			
Revenue	**38.94**	40.57	(4)
Royalties	**(7.18)**	(9.08)	(21)
Operating expenses	**(10.63)**	(9.89)	7
Net transportation expenses (non-GAAP)	**(4.00)**	(3.54)	13
Operating netback (non-GAAP)	**17.13**	18.06	(5)

During the three months ended March 31, 2025, Coelacanth generated an operating netback (see “Non-GAAP and Other Financial Measures”) of $17.13/boe, consistent with $18.06/boe for the comparative period in 2024.

The following is a reconciliation of operating netback per boe to net loss per boe for the periods noted:

	Three Months Ended March 31		
($/boe)	**2025**	2024	% Change
Operating netback	**17.13**	18.06	(5)
Depletion and depreciation	**(14.30)**	(14.42)	(1)
General and administrative expenses	**(21.76)**	(13.86)	57
Share based compensation	**(18.46)**	(10.11)	83
Finance expense	**(12.86)**	(1.06)	1,113
Finance income	**1.46**	10.60	(86)
Unutilized transportation	**(4.05)**	(2.49)	63
Net loss	**(52.84)**	(13.28)	298

The following is a reconciliation of operating netback to net loss for the periods noted:

	Three Months Ended March 31		
($000s)	**2025**	2024	% Change
Operating netback	**1,173**	1,631	(28)
Depletion and depreciation	**(979)**	(1,303)	(25)
General and administrative expenses	**(1,489)**	(1,252)	19
Share based compensation	**(1,264)**	(913)	38
Finance expense	**(881)**	(96)	818
Finance income	**100**	957	(90)
Unutilized transportation	**(277)**	(225)	23
Net loss	**(3,617)**	(1,201)	201

DEPLETION AND DEPRECIATION	Three Months Ended March 31		
	2025	2024	% Change
Depletion and depreciation ($000s)	**979**	1,303	(25)
Depletion and depreciation ($/boe)	**14.30**	14.42	(1)

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. Depletion and depreciation for the three months ended March 31, 2025 decreased to $1.0 million from $1.3 million for the comparative period in 2024 as a result of decreased production. On a per boe basis, depletion and depreciation for the three months ended March 31, 2025 was $14.30/boe, consistent with $14.42/boe for the comparative period in 2024.

Included in depletion and depreciation expense for the three months ended March 31, 2025 is $22 thousand (March 31, 2024 - $0.1 million) related to the Company's right-of-use assets.

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

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

At March 31, 2025 and March 31, 2024, the Company evaluated its exploration and evaluation assets for indicators of impairment and as a result of this assessment management determined that an impairment test was not required to be performed.

GENERAL AND ADMINISTRATIVE	Three Months Ended March 31		
($000s)	**2025**	2024	% Change
G&A expenses (gross)	**1,613**	1,286	25
G&A capitalized	**(124)**	(34)	265
G&A expenses (net)	**1,489**	1,252	19
G&A expenses ($/boe)	**21.76**	13.86	57

Net general and administrative expenses ("G&A") totaled $1.5 million for the three months ended March 31, 2025, an increase from $1.3 million for the comparative period in 2024 mainly due to higher employment costs.

On a per unit basis G&A increased to $21.76/boe for the three months ended March 31, 2025 compared to $13.86/boe for the comparative period in 2024 due to the decrease in production.

SHARE BASED COMPENSATION

	Three Months Ended March 31		
($000s)	**2025**	2024	% Change
Share based compensation (gross)	**1,454**	1,028	41
Share based compensation (capitalized)	**(190)**	(115)	65
Share based compensation (net)	**1,264**	913	38
Share based compensation ($/boe)	**18.46**	10.11	83

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 increased to $1.3 million for the three months ended March 31, 2025 compared to $0.9 million for the comparative period in 2024 due to stock option and RSU grants occurring in January 2025 compared to March 2024.

FINANCE EXPENSE

	Three Months Ended March 31		
	2025	2024	% Change
Interest expense	**604**	8	7,450
Lease interest expense	**5**	25	(80)
Accretion of other obligations	**205**	-	100
Accretion of decommissioning obligations	**67**	63	6
Finance expense	**881**	96	818
Finance expense ($/boe)	**12.86**	1.06	1,113

Accretion expense of decommissioning obligations was consistent for the three months ended March 31, 2025 compared to the same period in 2024. Interest expense relates to interest expense and standby fees on the credit facilities, outstanding letters of guarantee for firm transportation agreements and amortization of financing costs. The large increase stems from moving from a positive cash balance at March 31, 2024 to being drawn $15.0 million on its credit facilities at March 31, 2025 as a result of capital expenditures during the past twelve months**.**

FINANCE INCOME

Finance income relates to interest earned on cash in the bank. Finance income totaled $0.1 million for the three months ended March 31, 2025 compared to $1.0 million for the comparative period in 2024. The decrease corresponds to the decrease in the Company's cash balance over the comparative periods mainly due to capital expenditures during the past twelve months.

DEFERRED INCOME TAXES

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

Estimated tax pools at March 31, 2025 total approximately $278.0 million (December 31, 2024 - $264.9 million).

CASH FLOW FROM OPERATING ACTIVITIES AND ADJUSTED FUNDS USED

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

	Three Months Ended March 31		
($000s)	**2025**	2024	% Change
Cash flow from operating activities	**981**	3,256	(70)
Add (deduct):			
Decommissioning expenditures	**139**	148	(6)
Change in restricted cash deposits	**-**	424	(100)
Change in non-cash working capital	**(2,560)**	(2,750)	(7)
Adjusted funds flow (used) (non-GAAP)	**(1,440)**	1,078	(234)

Adjusted funds used (see "Non-GAAP and Other Financial Measures") was $1.4 million ($nil per basic and diluted share) for the three months ended March 31, 2025 and adjusted funds flow was $1.1 million ($nil per basic and diluted share) for the comparative period in 2024. The large decrease was mainly the result of increased interest expense and lower interest income, payments on financing obligation, and lower revenues stemming from production declines.

Cash flow from operating activities for the three months ended March 31, 2025 was $1.0 million ($nil per basic and diluted share) and $3.3 million ($0.01 per basic and diluted share) for the comparative period in 2024. Cash flow from operating activities differs from adjusted funds flow (used) due to the inclusion of changes in non-cash working capital, movements in restricted cash deposits and expenditures on decommissioning obligations. The decrease in cash flow from operating activities for the three months ended March 31, 2025 compared to Q1 2024 was mainly the result of increased interest expense, lower interest income, payments on financing obligation, lower revenues stemming from production declines and a decrease in changes in restricted cash deposits.

NET LOSS

The Company incurred a net loss of $3.6 million ($0.01 per basic and diluted share) for the three months ended March 31, 2025, up from $1.2 million ($nil per basic and diluted share) for the comparative period in 2024 due to increased interest expense, lower interest income, and lower revenues stemming from production declines.

CAPITAL EXPENDITURES	**Three Months Ended March 31**		
($000s)	**2025**	2024	% Change
Land	**200**	241	(17)
Drilling, completions, and workovers	**343**	121	183
Equipment	**25,101**	879	2,756
Geological and geophysical	**57**	22	159
Total expenditures	**25,701**	1,263	1,935

During the three months ended March 31, 2025 and March 31, 2024, the Company continued with facility procurement at Two Rivers East. Commercial production from Two Rivers East is expected to start with the completion of the facility in June 2025.

LIQUIDITY AND CAPITAL RESOURCES

Management uses adjusted working capital (deficiency) (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, 2025**	December 31, 2024	% Change
Current assets	**3,431**	11,579	(70)
Less:			
Current liabilities	**(36,009)**	(37,234)	(3)
Working capital deficiency	**(32,578)**	(25,655)	27
Add:			
Restricted cash deposits	**4,900**	4,900	-
Current portion of decommissioning obligations	**1,968**	2,118	(7)
Adjusted working capital deficiency (Capital management measure)	**(25,710)**	(18,637)	38

At March 31, 2025, the Company had an adjusted working capital deficiency of $25.7 million, which includes $15.0 million drawn under its credit facilities.

On October 4, 2024, the Company secured two revolving bank credit facilities for a total of $52.0 million from a Canadian chartered bank. The credit facilities are backed by reserves at Two Rivers West plus a $45.0 million letter of credit from a third party. The commitment from the third party is for a two-year term. During the term, Coelacanth anticipates that the lending value of producing reserves at Two Rivers East will allow for the credit facility to be renegotiated and the letter of credit to be returned, however, there can be no assurance that such agreements will be reached.

The first credit facility is a $7.0 million revolving operating demand loan credit facility that bears interest at prime plus 3.0%. The undrawn portion of the credit facility is subject to a standby fee of 1.0%. Any outstanding letters of guarantee reduce the amount that can be borrowed under the credit facility and bear interest at 4.0%. As at March 31, 2025, the Company had $6.0 million of outstanding letters of guarantee (December 31, 2024 - $5.4 million) under the revolving operating demand loan credit facility thereby reducing the amount available from $7.0 million to $1.0 million.

The second credit facility is a $45.0 million revolving operating demand loan that bears interest at prime plus 0.25%. The undrawn portion of the credit facility is subject to a standby fee of 0.125%. This credit facility is secured by a $45.0 million letter of credit from a third party. The letter of credit fee is 3.0% of the total $45.0 million face value of the letter of credit whether drawn or not for the first one-year term plus the period prior to the start of the first term. The first term starts the earlier of when drawn or December 31, 2024. The Company has the option to extend the term by an additional maximum one-year term for a fee of 6% of the drawn portion of the letter of credit that can be reduced at any time by repayment of the credit facility. As at March 31, 2025, the Company had $30.0 million of available capacity on the credit facility (December 31, 2024 - $45.0 million).

The credit facilities and letter of credit are secured by a $75.0 million fixed and floating charge debenture on the assets of the Company. The next review of the credit facilities by the bank is scheduled on or before June 30, 2025.

The credit facilities include 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 by its creditor, is calculated as current assets plus any undrawn amounts available on its demand loan credit facilities less current liabilities excluding any current portion drawn on the demand loan credit facilities. 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, 2025.

During the three months ended March 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. The Company is required to repay the principal amount over a five-year period at an interest rate of 12.0% with payments commencing on the in-service date of the Company's Two Rivers East facility (expected to be in June 2025).

Management anticipates that the Company will continue to have adequate liquidity to fund budgeted capital investments through a combination of its cash balance, cash flow, equity, and debt if required, pending commodity pricing, capital execution, and operational performance. Coelacanth's capital program is flexible and can be adjusted as needed based upon the current economic environment. The Company will continue to monitor the economic environment and the possible impact on its business and strategy and will make adjustments as necessary.

CONTRACTUAL OBLIGATIONS

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

($000s)	Total	Less than One Year	One to Three Years	After Three Years
Accounts payable and accrued liabilities	15,882	15,882	-	-
Revolving credit facility	15,000	15,000	-	-
Other obligations	23,190	2,768	8,807	11,615
Financing obligation payable	900	900	-	-
Decommissioning obligations	9,772	1,968	471	7,333
Operating commitments	517	194	323	-
Firm transportation agreements	172,487	4,326	13,755	154,406
Firm processing agreements	96,255	5,396	17,734	73,125
Property, plant, and equipment	1,393	1,393	-	-
Total contractual obligations	335,396	47,827	41,090	246,479

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) and then to Chicago through October 31, 2026.
- 10.0 mmcf/d to deliver natural gas to Westcoast Station 2 from January 1, 2023 through July 31, 2038.
- 50.0 mmcf/d to deliver natural gas to Westcoast Station 2 from June 1, 2023 through May 31, 2038.
- 15.0 mmcf/d to deliver natural gas to Westcoast Station 2 from May 1, 2024 through April 30, 2055.
- 25.0 mmcf/d to deliver natural gas to Westcoast Station 2 from August 1, 2028 through July 31, 2043.

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

- 4.4 mmcf/d to deliver natural gas to Westcoast Station 2 from April 1, 2023 through March 31, 2026.
- 10.0 mmcf/d to deliver natural gas to Westcoast Station 2 from June 1, 2023 through December 31, 2027.
- 20.0 mmcf/d to deliver natural gas to Westcoast Station 2 from October 1, 2023 through October 31, 2026.
- 10.0 mmcf/d to deliver natural gas to Westcoast Station 2 from November 1, 2024 through December 31, 2025.

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

Firm processing agreements include 30.0 mmcf/d of processing services at a gas processing facility for a period of 10 years. Under the terms of the processing agreement, the Company can elect prior to July 1, 2025 to increase the volume by an additional 10.0 mmcf/d (40.0 mmcf/d total) starting July 1, 2026 and can then 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 has agreed to fund the extension of their gathering system to connect to the Company's Two Rivers East project. During the three months ended March 31, 2025, the Company received $22.7 million from the midstream company. The Company is required to repay the principal amount over a five-year period at an interest rate of 12.0% upon the commencement of the in-service date of the Company's Two Rivers East facility (expected to be in June 2025). This balance is included in other obligations.

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 pipeline 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, 2025**	May 28, 2025
Voting common shares	**532,202**	532,202
Warrants	**62,710**	62,710
Stock options	**22,354**	22,354
Restricted share units	**7,611**	7,611
Total	**624,877**	624,877

SUMMARY OF QUARTERLY RESULTS

	Q1 2025	Q4 2024	Q3 2024	Q2 2024	Q1 2024	Q4 2023	Q3 2023	Q2 2023
Average Daily Production								
Oil and NGLs (bbls/d)	**209**	502	254	323	337	447	46	67
Natural gas (mcf/d)	**3,311**	3,490	3,450	3,724	3,934	2,858	929	1,321
Oil equivalent (boe/d)	**761**	1,084	829	944	993	923	201	287
($000s, except per share amounts)								
Oil and natural gas sales	**2,666**	4,544	2,362	3,164	3,666	4,204	679	826
Cash flow from (used in)								
operating activities	**981**	3,157	(3,730)	(480)	3,256	(404)	(2,553)	765
Per share basic and diluted (2)	**-**	0.01	(0.01)	(-)	0.01	(-)	(0.01)	(-)
Adjusted funds flow (used) (1)	**(1,440)**	382	(207)	262	1,078	1,750	(773)	(756)
Per share basic and diluted	**(-)**	-	(-)	-	-	-	(-)	(-)
Net loss	**(3,617)**	(2,903)	(2,464)	(2,329)	(1,201)	(750)	(1,869)	(2,165)
Per share basic and diluted	**(0.01)**	(0.01)	(-)	(-)	(-)	(-)	(-)	(0.01)

(1) Adjusted funds flow (used) and adjusted funds flow (used) per share do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. Please refer to the "Non-GAAP and Other Financial Measures" section for more details and the "Cash Flow From Operating Activities and Adjusted Funds Flow (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 Company experienced normal production declines on the Two Rivers property from Q2 2023 to Q3 2023. The increase in production, oil and natural gas sales, cash flow from operating activities, and adjusted funds flow between Q4 2023 and Q4 2024 stems from two new wells at Two Rivers West coming on-stream in Q4 2023 and 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 Q1 2025 was mainly the result of increased interest expense and lower interest income, payments on financing obligation, and lower revenues stemming from production declines. 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, 2024 for the Company's material accounting policies.

FUTURE ACCOUNTING PRONOUNCEMENTS

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

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

CRITICAL ACCOUNTING ESTIMATES

Management is required to make estimates, judgments, and assumptions in the application of IFRS that affect the reported amounts of assets and liabilities at the date of the financial statements and revenues and expenses for the period then ended. Certain of these estimates may change from period to period resulting in a material impact on the Company's results from operations and financial position (see note 2d in the notes to the Company's December 31, 2024 financial statements for full descriptions of the use of estimates and judgments).

RISK ASSESSMENT

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

Reserves and reserve replacement

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

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

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

Operational risks

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

Market risk

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

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

Interest rate risk
The Company is exposed to interest rate risk on its cash, restricted cash deposit, and credit facility balances. The Company currently does not use interest rate hedges or fixed interest rate contracts to manage the Company's exposure to interest rate fluctuations. The amount drawn on the Company's credit facilities at March 31, 2025 was $15.0 million (December 31, 2024 - $nil).

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

Credit risk

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

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

The maximum exposure to credit risk is represented by the carrying amount of cash, restricted cash deposits and accounts receivable on the statement of financial position. At March 31, 2025, $1.9 million (97%) of the Company's outstanding accounts receivable were current and $66 thousand (3%) were outstanding for more than 90 days. During the three months ended March 31, 2025, the Company deemed $3 thousand of outstanding accounts receivable to be uncollectable (March 31, 2024 - $9 thousand).

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

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's processes for managing liquidity risk includes ensuring, to the extent possible, that it will have sufficient liquidity to meet its liabilities when they become due. The Company prepares annual, quarterly, and monthly capital expenditure budgets, which are monitored and updated as required, and requires authorizations for expenditures on projects to assist with the management of capital. Budgets and forecasting are subject to significant judgment and estimates relating to activity levels, future cash flows and timing thereof, and other factors which may not be within the control of the Company. In managing liquidity risk, the Company ensures that it has access to additional financing, including potential equity issuances and additional debt financing which depend on, among other things, the current commodity price environment, operating performance, and the Company's ability to access equity and debt capital markets. There is no assurance this capital will be available. In the event the Company requires additional funding and is not successful in obtaining additional funding or of obtaining funding on terms that are acceptable to the Company, this may impact the Company's ability to develop and maintain its oil and gas properties. The Company also mitigates liquidity risk by maintaining an insurance program to minimize exposure to insurable losses.

To facilitate its capital expenditure program, the Company has two revolving credit facilities (refer to the "Liquidity and Capital Resources" section). At March 31, 2025, the Company had an adjusted working capital deficiency of $25.7 million which includes $15.0 million drawn under its credit facilities. During the three months ended March 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. This amount will be repaid over a five-year period at an interest rate of 12.0% upon the commencement of the in-service date of the Company's Two Rivers East facility (expected to be in June 2025). The Company's available lending capacity will be used to fund the remaining forecasted capital of approximately $13.9 million to complete facility and infrastructure projects and commence operations at Two Rivers East in June 2025. As at March 31, 2025, the Company had $6.0 million of outstanding letters of guarantee under the revolving operating demand loan credit facility thereby reducing the amount available from $7.0 million to $1.0 million, and $15.0 million drawn on the second credit facility reducing the amount available to $30.0 million.

The Company forecasts 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, pending commodity pricing, capital execution, and operational performance. Coelacanth's capital program is flexible and can be adjusted as needed based upon the current economic environment. The Company will continue to monitor the economic environment and the possible impact on its business and strategy and will make adjustments as necessary.

Safety and Environmental Risks

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

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, 2024, which is available on the SEDAR+ website at www.sedarplus.com.

PRODUCT TYPES

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

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

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

Sales Volumes by Product Type	**Q1 2025**	Q4 2024	Q3 2024	Q2 2024	Q1 2024	Q4 2023	Q3 2023	Q2 2023
Condensate (bbls/d)	**18**	22	33	56	19	12	4	6
Other NGLs (bbls/d)	**25**	29	33	39	37	28	7	14
NGLs (bbls/d)	**43**	51	66	95	56	40	11	20
Tight oil (bbls/d)	**166**	451	188	228	281	407	35	47
Condensate (bbls/d)	**18**	22	33	56	19	12	4	6
Oil and condensate (bbls/d)	**184**	473	221	284	300	419	39	53
Other NGLs (bbls/d)	**25**	29	33	39	37	28	7	14
Oil and NGLs (bbls/d)	**209**	502	254	323	337	447	46	67
Shale gas (mcf/d)	**3,311**	3,490	3,450	3,724	3,934	2,858	929	1,321
Natural gas (mcf/d)	**3,311**	3,490	3,450	3,724	3,934	2,858	929	1,321
Oil equivalent (boe/d)	**761**	1,084	829	944	993	923	201	287

TEST RESULTS AND INITIAL PRODUCTION RATES

The 5-19 Lower Montney well was production tested for 9.4 days and produced at an average rate of 377 bbl/d oil and 2,202 mcf/d gas (net of load fluid and energizing fluid) over that period which includes the initial cleanup where only load water was being recovered. At the end of the test, flowing wellhead pressure and production rates were stable.

The A5-19 Basal Montney well was production tested for 5.9 days and produced at an average rate of 117 bbl/d oil and 630 mcf/d gas (net of load fluid and energizing fluid) over that period which includes the initial cleanup where only load water was being recovered. At the end of the test, flowing wellhead pressure and production rates were stable.

The B5-19 Upper Montney well was production tested for 6.3 days and produced at an average rate of 92 bbl/d oil and 2,100 mcf/d gas (net of load fluid and energizing fluid) over that period which includes the initial cleanup where only load water was being recovered. At the end of the test, flowing wellhead pressure and production rates were stable.

The C5-19 Lower Montney well was production tested for 5.8 days and produced at an average rate of 736 bbl/d oil and 2,660 mcf/d gas (net of load fluid and energizing fluid) over that period which includes the initial cleanup where only load water was being recovered. At the end of the test, flowing wellhead pressure and production rates were stable.

The D5-19 Lower Montney well was production tested for 12.6 days and produced at an average rate of 170 bbl/d oil and 580 mcf/d gas (net of load fluid and energizing fluid) over that period which includes the initial cleanup where only load water was being recovered. At the end of the test, flowing wellhead pressure and production rates were stable.

The E5-19 Lower Montney well was production tested for 11.4 days and produced at an average rate of 312 bbl/d oil and 890 mcf/d gas (net of load fluid and energizing fluid) over that period which includes the initial cleanup where only load water was being recovered. At the end of the test, flowing wellhead pressure was stable, and production was starting to decline.

The F5-19 Lower Montney well was production tested for 4.9 days and produced at an average rate of 728 bbl/d oil and 1,607 mcf/d gas (net of load fluid and energizing fluid) over that period which includes the initial cleanup where only load water was being recovered. At the end of the test, flowing wellhead pressure and production rates were stable.

The G5-19 Lower Montney well was production tested for 7.1 days and produced at an average rate of 415 bbl/d oil and 1,489 mcf/d gas (net of load fluid and energizing fluid) over that period which includes the initial cleanup where only load water was being recovered. At the end of the test, flowing wellhead pressure and production rates were stable.

The H5-19 Lower Montney well was production tested for 8.1 days and produced at an average rate of 411 bbl/d oil and 1,166 mcf/d gas (net of load fluid and energizing fluid) over that period which includes the initial cleanup where only load water was being recovered. At the end of the test, flowing wellhead pressure was stable and production was starting to decline.

A pressure transient analysis or well-test interpretation has not been carried out on these nine wells and thus certain of the test results provided herein should be considered to be preliminary until such analysis or interpretation has been completed. Test results and initial production rates disclosed herein, particularly those short in duration, may not necessarily be indicative of long-term performance or of ultimate recovery.

Any references to peak rates, test rates, IP30, IP90, IP180 or initial production rates or declines are useful for confirming the presence of hydrocarbons, however, such rates and declines are not determinative of the rates at which such wells will continue production and decline thereafter and are not indicative of long-term performance or ultimate recovery. IP30 is defined as an average production rate over 30 consecutive days, IP90 is defined as an average production rate over 90 consecutive days and IP180 is defined as an average production rate over 180 consecutive days. Readers are cautioned not to place reliance on such rates in calculating aggregate production for the Company.

FORWARD-LOOKING INFORMATION

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

More particularly and without limitation, this MD&A contains forward-looking statements and information relating to the Company’s oil and condensate, other NGLs, and natural gas production, royalty rates, capital programs, and adjusted working capital. 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.

ADDITIONAL INFORMATION

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

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

($000s)	Note	**March 31 2025**	December 31 2024
Assets			
Current assets			
Cash		**1,068**	5,693
Accounts receivable		**2,014**	4,730
Prepaid expenses and deposits		**349**	1,156
		3,431	11,579
Restricted cash deposits	(4)	**4,900**	4,900
Property, plant, and equipment	(5)	**42,174**	42,381
Exploration and evaluation assets	(6)	**179,492**	154,178
		226,566	201,459
		229,997	213,038
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities		**15,882**	33,768
Revolving credit facility	(8)	**14,491**	-
Current portion of other obligations	(7)	**2,768**	110
Financing obligation payable	(8)	**900**	1,238
Current portion of decommissioning obligations	(9)	**1,968**	2,118
		36,009	37,234
Other obligations	(7)	**20,422**	244
Decommissioning obligations	(9)	**7,804**	7,531
		64,235	45,009
Shareholders' Equity			
Shareholders' capital	(10)	**176,502**	175,307
Warrants	(10)	**6,979**	6,979
Contributed surplus		**7,292**	7,137
Deficit		**(25,011)**	(21,394)
		165,762	168,029
		229,997	213,038
Commitments	(17)		

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

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

($000s, except per share amounts)	**Note**	**Three Months Ended March 31 2025**	2024
Revenue			
Oil and natural gas sales	(16)	**2,666**	3,666
Royalties		**(491)**	(821)
		2,175	2,845
Expenses			
Operating		**728**	894
Transportation		**551**	545
Depletion and depreciation	(5)	**979**	1,303
General and administrative		**1,489**	1,252
Share based compensation	(11)	**1,264**	913
Finance income		**(100)**	(957)
Finance expense		**881**	96
		5,792	4,046
Net loss and comprehensive loss		**(3,617)**	(1,201)
Net loss per share			
Basic and diluted	(12)	**(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, 2023		173,918	6,562	4,119	(12,080)	172,519
Net loss		-	-	-	(1,201)	(1,201)
Exercise of warrants		564	-	(564)	-	-
Share based compensation	(11)	-	-	1,028	-	1,028
Balance, March 31, 2024		174,482	6,562	4,583	(13,281)	172,346
Balance, December 31, 2024		**175,307**	**6,979**	**7,137**	**(21,394)**	**168,029**
Net loss		**-**	**-**	**-**	**(3,617)**	**(3,617)**
Settlement of vested RSUs	(10)	**1,195**	**-**	**(1,195)**	**-**	**-**
Settlement of stock options	(11)	**-**	**-**	**(104)**	**-**	**(104)**
Share based compensation	(11)	**-**	**-**	**1,454**	**-**	**1,454**
Balance, March 31, 2025		**176,502**	**6,979**	**7,292**	**(25,011)**	**165,762**

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**	**2025**	2024
Operating Activities			
Net loss		**(3,617)**	(1,201)
Depletion and depreciation	(5)	**979**	1,303
Share based compensation	(11)	**1,264**	913
Finance expense		**881**	96
Interest paid		**(609)**	(33)
Financing obligation payments	(8)	**(338)**	-
Decommissioning expenditures	(9)	**(139)**	(148)
Restricted cash deposits	(4)	**-**	(424)
Change in non-cash working capital	(15)	**2,560**	2,750
		981	3,256
Financing Activities			
Revolving credit facility	(8)	**15,000**	-
Proceeds from other obligations	(7)	**22,658**	-
Payment of other obligations	(7)	**(27)**	(105)
Settlement of stock options	(11)	**(104)**	-
Change in non-cash working capital	(15)	**187**	(273)
		37,714	(378)
Investing Activities			
Capital expenditures - property, plant, and equipment	(5)	**(668)**	(393)
Capital expenditures - exploration and evaluation assets	(6)	**(25,033)**	(870)
Change in non-cash working capital	(15)	**(17,619)**	(22,325)
		(43,320)	(23,588)
Change in cash		**(4,625)**	(20,710)
Cash, beginning of period		**5,693**	82,568
Cash, end of period		**1,068**	61,858

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

(Tabular amounts in 000s, unless otherwise stated)

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, 2024.

The condensed interim financial statements were authorized for issuance by the Board of Directors on May 28, 2025.

(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, 2024.

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, 2024. The accounting policies have been applied consistently by the Company to all periods presented in these condensed interim financial statements.

4. RESTRICTED CASH DEPOSITS

The Company has $4.9 million in restricted guaranteed investment certificates ("GIC's") with a Canadian chartered bank (December 31, 2024 - $4.9 million). These restricted GIC's are being held as security for $4.9 million of letters of guarantee to third parties relating to firm transportation agreements. Restricted cash deposits will be released as letters of guarantee are lowered or if the restricted GIC's are replaced by a credit facility (see note 8).

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

5. PROPERTY, PLANT, AND EQUIPMENT

Cost	Total
Balance, December 31, 2024	95,613
Additions	**668**
Capitalized share based compensation	**15**
Change in decommissioning obligation estimates (note 9)	**89**
Balance, March 31, 2025	**96,385**

Accumulated Depletion, Depreciation, and Impairment	Total
Balance, December 31, 2024	53,232
Depletion and depreciation	**979**
Balance, March 31, 2025	**54,211**

Net Book Value	Total
December 31, 2024	42,381
March 31, 2025	**42,174**

During the three months ended March 31, 2025, approximately $9 thousand (March 31, 2024 - $17 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, 2025 included an estimated $21.4 million (March 31, 2024 - $19.4 million) for forecasted future development costs associated with proved and probable undeveloped oil and natural gas reserves and excluded approximately $1.0 million (March 31, 2024 - $1.2 million) for the estimated salvage value of production equipment and facilities. Depletion expense on development and production assets was $0.9 million for the three months ended March 31, 2025 (March 31, 2024 - $1.2 million).

Included in depletion and depreciation expense for the three months ended March 31, 2025, is $22 thousand (March 31, 2024 - $0.1 million) related to the Company's right-of-use assets. At March 31, 2025, the net book value of the right-of-use assets is $0.2 million (December 31, 2024 - $0.3 million).

Impairment assessment

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

6. EXPLORATION AND EVALUATION ASSETS

	Total
Balance, December 31, 2024	154,178
Additions	**25,033**
Change in decommissioning obligation estimates (note 9)	**106**
Capitalized share based compensation	**175**
Balance, March 31, 2025	**179,492**

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. Included in E&E assets at March 31, 2025 is approximately $160.8 million relating to pad drilling and completions and pipeline and facility construction costs related to the Company's Two Rivers East project (December 31, 2024 - $135.5 million).

During the three months ended March 31, 2025, approximately $0.1 million (March 31, 2024 - $17 thousand) of directly attributable general and administrative costs were capitalized as expenditures on E&E assets.

At March 31, 2025, the Company evaluated its E&E assets for indicators of impairment and as a result of this assessment management determined that an impairment test was not required to be performed.

7. OTHER OBLIGATIONS

	Pipeline obligation	Lease obligation	Total
Balance, December 31, 2024	-	354	354
Additions	**22,700**	**-**	**22,700**
Transaction costs	**(42)**	**-**	**(42)**
Lease payments	**-**	**(32)**	**(32)**
Interest expense	**-**	**5**	**5**
Accretion	**205**	**-**	**205**
Balance, March 31, 2025	**22,863**	**327**	**23,190**
Current	**2,654**	**114**	**2,768**
Long-term	**20,209**	**213**	**20,422**
	22,863	**327**	**23,190**

Pipeline obligation
During the three months ended March 31, 2025, the Company received $22.7 million from a midstream company for the transfer of the extension of its gathering system (that is, 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 E&E assets 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 (expected to be in June 2025).

Lease obligation
The Company has the following lease bligation in place as at March 31, 2025:

- Office lease commencing December 1, 2021. The lease obligation is discounted with an effective interest rate of 5.5% and the right-of-use asset is amortized based on the lease term. The lease expires November 30, 2027 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.

The total undiscounted amount of the estimated future cash flows to settle the lease obligation over the remaining term is $0.4 million. The Company’s minimum lease payments are as follows:

	March 31, 2025
Within one year	129
Later than one year but not later than three years	224
Minimum lease payments	353
Amount representing interest expense	(26)
Present value of net lease and other obligation payments	**327**

8. CREDIT FACILITIES

On October 4, 2024, the Company secured two revolving bank credit facilities for a total of $52.0 million from a Canadian chartered bank. The credit facilities are backed by reserves at Two Rivers West plus a $45.0 million letter of credit from a third party. The commitment from the third party is for a two-year term. During the term, Coelacanth anticipates that the lending value of producing reserves at Two Rivers East will allow for the credit facility to be renegotiated and the letter of credit to be returned, however, there can be no assurance that such agreements will be reached.

The first credit facility is a $7.0 million revolving operating demand loan credit facility that bears interest at prime plus 3.0%. The undrawn portion of the credit facility is subject to a standby fee of 1.0%. Any outstanding letters of guarantee reduce the amount that can be borrowed under the credit facility and bear interest at 4.0%. As at March 31, 2025, the Company had $6.0 million of outstanding letters of guarantee (December 31, 2024 - $5.4 million) under the revolving operating demand loan credit facility thereby reducing the amount available from $7.0 million to $1.0 million.

The second credit facility is a $45.0 million revolving operating demand loan that bears interest at prime plus 0.25%. The undrawn portion of the credit facility is subject to a standby fee of 0.125%. This credit facility is secured by a $45.0 million letter of credit from a third party. The letter of credit fee is 3.0% of the total $45.0 million face value of the letter of credit whether drawn or not for the first one-year term plus the period prior to the start of the first term. The first term starts the earlier of when drawn or December 31, 2024. The Company has the option to extend the term by an additional maximum one-year term for a fee of 6% of the drawn portion of the letter of credit that can be reduced at any time by repayment of the credit facility. At March 31, 2025, the Company had $30.0 million of available capacity on the credit facility (December 31, 2024 - $45.0 million). The non-refundable third party letter of credit fees for the initial one-year term have been recognized as a financing obligation payable that are payable monthly until December 2025. The balance of the financing obligation payable at March 31, 2025 is $0.9 million (December 31, 2024 - $1.2 million).

The credit facilities and letter of credit are secured by a $75.0 million fixed and floating charge debenture on the assets of the Company. The next review of the credit facilities by the bank is scheduled on or before June 30, 2025.

As at March 31, 2025, $15.0 million has been drawn under its credit facilities (December 31, 2024 - $nil) and $0.5 million of unamortized debt issuance costs have been presented as a reduction to the balance drawn and will be amortized as finance expense over the remaining term.

The credit facilities include 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 by its creditor, is calculated as current assets plus any undrawn amounts available on its demand loan credit facilities less current liabilities excluding any current portion drawn on the demand loan credit facilities. The definition of current assets and current liabilities excludes the fair value of risk management contracts and amounts associated with the pipeline obligation (note 7). The Company was compliant with this covenant at March 31, 2025.

9. DECOMMISSIONING OBLIGATIONS

The Company's decommissioning obligations result from its ownership interest in development and production assets including well sites and gathering systems. The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to abandon and reclaim the wells and facilities, and the estimated timing of the costs to be incurred in future periods. The total undiscounted amount of the estimated cash flows, adjusted for inflation at 1.82% per year (December 31, 2024 - 1.81%) required to settle the decommissioning obligations is approximately $16.6 million (December 31, 2024 - $16.7 million) which is estimated to be incurred over the next 33 years. At March 31, 2025, a risk-free rate of 3.19% (December 31, 2024 - 3.32%) was used to calculate the net present value of the decommissioning obligations.

	Three Months Ended March 31, 2025	Year Ended December 31, 2024
Balance, beginning of period	**9,649**	8,869
Provisions incurred	**-**	1,407
Provisions settled	**(139)**	(1,427)
Revisions in estimated cash flows	**-**	565
Revisions due to change of rates	**195**	(35)
Accretion	**67**	270
Balance, end of period	**9,772**	9,649
Current	**1,968**	2,118
Long-term	**7,804**	7,531
	9,772	9,649

10. SHAREHOLDERS' CAPITAL AND WARRANTS

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

Voting Common Shares	**Number**	**Amount**
Balance, December 31, 2024	530,670	175,307
Settlement of vested restricted share units	**1,532**	**1,195**
Balance, March 31, 2025	**532,202**	**176,502**

Warrants	**Number**	**Amount**
Balance, December 31, 2024 and March 31, 2025	**62,710**	**6,979**

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

Issue Date	**Expiry Date**	**Exercise Price**	**Number**
June 10, 2022	June 10, 2027	$0.27	27,502
November 15, 2023	June 30, 2025	$1.05	33,333
November 16, 2023	November 16, 2028	$0.80	1,875
			62,710

11. SHARE BASED COMPENSATION PLANS

Stock options

The Company has authorized and reserved for issuance 53.2 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, 2025, 22.4 million options were outstanding at an average exercise price of $0.75 per share.

	Number of Options	Weighted Average Exercise Price ($)
Balance, December 31, 2024	16,971	0.72
Granted	**5,727**	**0.81**
Settled	**(344)**	**0.61**
Balance, March 31, 2025	**22,354**	**0.75**
Exercisable, March 31, 2025	**8,453**	**0.70**

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

	Options Outstanding			Options Exercisable	
Exercise Price	Number	Weighted Average Remaining Life (years)	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
$0.54 to $0.70	4,457	2.4	0.56	2,754	0.54
$0.71 to $0.79	4,547	2.8	0.75	3,101	0.75
$0.80 to $0.83	13,350	4.3	0.80	2,598	0.80
	22,354	3.6	0.75	8,453	0.70

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

During the three months ended March 31, 2025, the Company recognized $0.7 million (March 31, 2024 - $0.5 million) of share based compensation related to the stock options of which $0.6 million was recognized as an expense and $88 thousand was capitalized (March 31, 2024 - $0.4 million was recognized as an expense and $61 thousand was capitalized). At March 31, 2025, there was $2.7 million remaining as unrecognized share based compensation related to the stock options.

During the three months ended March 31, 2025, the Company settled 0.3 million stock options (March 31, 2024 - nil) for $104 thousand in cash.

Restricted share units

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

	Number of RSUs
Balance, December 31, 2024	5,579
Granted	**3,564**
Exercised	**(1,532)**
Balance, March 31, 2025	**7,611**
Exercisable, March 31, 2025	**-**

The weighted average market price of the Company's common shares used to value the RSUs granted during the three months ended March 31, 2025 was $0.81 (March 31, 2024 - $0.80). During the three months ended March 31, 2025, the Company recognized $0.8 million (March 31, 2024 - $0.5 million) of share based compensation related to the RSUs of which $0.7 million was recognized as an expense and $0.1 million was capitalized (March 31, 2024 - $0.4 million was recognized as an expense and $54 thousand was capitalized). At March 31, 2025, there was $3.8 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.

12. PER SHARE AMOUNTS

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

	Three Months Ended March 31	
	2025	2024
Weighted average number of shares - basic	**531,445**	529,196
Dilutive effect of share based compensation plans and warrants	**-**	-
Weighted average number of shares - diluted	**531,445**	529,196

For the three months ended March 31, 2025, 22.4 million stock options, 7.6 million RSUs, and 62.7 million warrants were excluded from the weighted-average share calculation because they were anti-dilutive due to the net loss.

For the three months ended March 31, 2024, 18.7 million stock options, 7.3 million RSUs, and 62.7 million warrants were excluded from the weighted-average share calculation because they were anti-dilutive due to the net loss.

13. FINANCIAL RISK MANAGEMENT

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

Market risk

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

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

Interest rate risk
The Company is exposed to interest rate risk on its cash, restricted cash deposit, and credit facility balances. The Company currently does not use interest rate hedges or fixed interest rate contracts to manage the Company's exposure to interest rate fluctuations. The amount drawn on the Company's credit facilities at March 31, 2025 was $15.0 million (December 31, 2024 - $nil).

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

The Company did not enter into commodity price contracts to manage future cash flows as at March 31, 2025.

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

The maximum exposure to credit risk is represented by the carrying amount of cash, restricted cash deposits and accounts receivable on the statement of financial position. At March 31, 2025, $1.9 million (97%) of the Company's outstanding accounts receivable were current and $66 thousand (3%) were outstanding for more than 90 days. During the three months ended March 31, 2025, the Company deemed $3 thousand of outstanding accounts receivable to be uncollectable (March 31, 2024 - $9 thousand).

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

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's processes for managing liquidity risk includes ensuring, to the extent possible, that it will have sufficient liquidity to meet its liabilities when they become due. The Company prepares annual, quarterly, and monthly capital expenditure budgets, which are monitored and updated as required, and requires authorizations for expenditures on projects to assist with the management of capital. Budgets and forecasting are subject to significant judgment and estimates relating to activity levels, future cash flows, and timing thereof and other factors which may not be within the control of the Company. In managing liquidity risk, the Company ensures that it has access to additional financing, including potential equity issuances and additional debt financing which depend on, among other things, the current commodity price environment, operating performance, and the Company's ability to access equity and debt capital markets. There is no assurance this capital will be available. In the event the Company requires additional funding and is not successful in obtaining additional funding or of obtaining funding on terms that are acceptable to the Company, this may impact the Company's ability to develop and maintain its oil and gas properties. The Company also mitigates liquidity risk by maintaining an insurance program to minimize exposure to insurable losses.

To facilitate its capital expenditure program, the Company has two revolving credit facilities (see note 8). At March 31, 2025, the Company had an adjusted working capital deficiency of $25.7 million (see note 14) which includes $15.0 million drawn under its credit facilities. During the three months ended March 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. This amount will be repaid over a five-year period at an interest rate of 12.0% upon the commencement of the in-service date of the Company's Two Rivers East facility (see note 7). The Company's available lending capacity will be used to fund the remaining forecasted capital of approximately $13.9 million to complete facility and infrastructure projects and commence operations at Two Rivers East in June 2025. As at March 31, 2025, the Company had $6.0 million of outstanding letters of guarantee under the revolving operating demand loan credit facility thereby reducing the amount available from $7.0 million to $1.0 million, and $15.0 million drawn on the second credit facility reducing the amount available to $30.0 million.

The Company forecasts 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, pending commodity pricing, capital execution, and operational performance. Coelacanth's capital program is flexible and can be adjusted as needed based upon the current economic environment. The Company will continue to monitor the economic environment and the possible impact on its business and strategy and will make adjustments as necessary.

14. 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 and adjusted working capital (deficiency). Adjusted working capital (deficiency) includes current assets and restricted cash deposits less current liabilities, excluding the current portion of decommissioning obligations. 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, 2025	December 31, 2024
Shareholders' equity	**165,762**	168,029
Adjusted working capital deficiency	**(25,710)**	(18,637)

Management uses adjusted working capital (deficiency) as a measure to assess the Company's financial position and is reconciled as follows:

($000s)	**March 31, 2025**	December 31, 2024
Current assets	**3,431**	11,579
Less:		
Current liabilities	**(36,009)**	(37,234)
Working capital deficiency	**(32,578)**	(25,655)
Add:		
Restricted cash deposits	**4,900**	4,900
Current portion of decommissioning obligations	**1,968**	2,118
Adjusted working capital deficiency	**(25,710)**	(18,637)

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.

15. SUPPLEMENTAL CASH FLOW INFORMATION

	March 31, 2025	March 31, 2024
Accounts receivable	**2,716**	2,679
Prepaid expenses and deposits(1)	**298**	112
Accounts payable and accrued liabilities	**(17,886)**	(22,639)
Change in non-cash working capital	**(14,872)**	(19,848)
Relating to:		
Operating	**2,560**	2,750
Financing	**187**	(273)
Investing	**(17,619)**	(22,325)
Change in non-cash working capital	**(14,872)**	(19,848)

(1) As at March 31, 2025, excludes $0.5 million (March 31, 2024 - $nil) of debt issuance costs that were re-classified as a reduction to the revolving credit facility balance (note 8).

16. REVENUE

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

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

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

	Three Months Ended March 31	
	2025	2024
Oil and condensate	**1,495**	2,334
Other natural gas liquids	**85**	116
Natural gas	**1,086**	1,216
Total revenue	**2,666**	3,666

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	
	2025	2024
Natural gas production sales	**858**	975
Transportation revenue	**228**	241
Natural gas sales	**1,086**	1,216

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, two customers represented combined sales of 90% for the three months ended March 31, 2025 (March 31, 2024 - two customers represented combined sales of 93%).

17. COMMITMENTS

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

	2025	2026	2027	2028	2029	Thereafter	Total
Operating commitments	145	194	178	-	-	-	517
Firm transportation agreements	3,037	5,778	7,192	9,451	11,064	135,965	172,487
Firm processing agreements	3,212	8,736	8,910	9,089	9,270	57,038	96,255
Property, plant, and equipment	1,393	-	-	-	-	-	1,393
	7,787	14,708	16,280	18,540	20,334	193,003	270,652

Operating commitments include the non-lease variable components (operating expenses) of the head office lease (see note 7).

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

- 1.5 mmcf/d to deliver natural gas to the Alliance Trading Pool (ATP) and then to Chicago through October 31, 2026.
- 10.0 mmcf/d to deliver natural gas to Westcoast Station 2 from January 1, 2023 through July 31, 2038.
- 50.0 mmcf/d to deliver natural gas to Westcoast Station 2 from June 1, 2023 through May 31, 2038.
- 15.0 mmcf/d to deliver natural gas to Westcoast Station 2 from May 1, 2024 through April 30, 2055.
- 25.0 mmcf/d to deliver natural gas to Westcoast Station 2 from August 1, 2028 through July 31, 2043.

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

- 4.4 mmcf/d to deliver natural gas to Westcoast Station 2 from April 1, 2023 through March 31, 2026.
- 10.0 mmcf/d to deliver natural gas to Westcoast Station 2 from June 1, 2023 through December 31, 2027.
- 20.0 mmcf/d to deliver natural gas to Westcoast Station 2 from October 1, 2023 through October 31, 2026.
- 10.0 mmcf/d to deliver natural gas to Westcoast Station 2 from November 1, 2024 through December 31, 2025.

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

Firm processing agreements include 30.0 mmcf/d of processing services at a gas processing facility for a period of 10 years. Under the terms of the processing agreement, the Company can elect prior to July 1, 2025 to increase the volume by an additional 10.0 mmcf/d (40.0 mmcf/d total) starting July 1, 2026 and can then 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 agreed to fund the extension of their gathering system (see note 7).

CORPORATE INFORMATION

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FORWARD-LOOKING STATEMENTS

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

COELACANTH
ENERGY INC.