Q1 2024 RESULTS

FINANCIAL AND OPERATING RESULTS FOR THE THREE MONTHS ENDED MARCH 31, 2024

COELACANTH ENERGY INC.

FINANCIAL RESULTS	THREE MONTHS ENDED MARCH 31		
($000s, except per share amounts)	2024	2023	% Change
OIL AND NATURAL GAS SALES	**3,666**	954	284
CASH FLOW FROM (USED IN) OPERATING ACTIVITIES	**3,256**	(2,042)	(259)
Per share - basic and diluted (3)	**0.01**	(-)	100
ADJUSTED FUNDS FLOW (USED)(1)	**1,078**	(554)	(295)
Per share - basic and diluted	**-**	(-)	-
NET LOSS	**(1,201)**	(1,789)	(33)
Per share - basic and diluted	**(-)**	(-)	-
CAPITAL EXPENDITURES (4)	**1,263**	5,139	(75)
ADJUSTED WORKING CAPITAL (2)	**67,139**	61,215	10
COMMON SHARES OUTSTANDING (000s)			
Weighted average - basic and diluted	**529,196**	425,116	24
End of period - basic	**529,392**	425,384	24
End of period - fully diluted	**618,165**	469,358	32

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

(2) Adjusted working capital 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 **2024**	2023	% Change
Daily production [2]			
Oil and condensate (bbls/d)	**300**	46	552
Other NGLs (bbls/d)	**37**	14	164
Oil and NGLs (bbls/d)	**337**	60	462
Natural gas (mcf/d)	**3,934**	1,380	185
Oil equivalent (boe/d)	**993**	290	242
Oil and natural gas sales			
Oil and condensate ($/bbl)	**85.30**	94.78	(10)
Other NGLs ($/bbl)	**34.79**	42.98	(19)
Oil and NGLs ($/bbl)	**79.82**	82.72	(4)
Natural gas ($/mcf)	**3.40**	4.11	(17)
Oil equivalent ($/boe)	**40.57**	36.60	11
Royalties			
Oil and NGLs ($/bbl)	**20.77**	26.31	(21)
Natural gas ($/mcf)	**0.51**	1.02	(50)
Oil equivalent ($/boe)	**9.08**	10.26	(12)
Operating expenses			
Oil and NGLs ($/bbl)	**9.89**	16.93	(42)
Natural gas ($/mcf)	**1.65**	2.82	(41)
Oil equivalent ($/boe)	**9.89**	16.93	(42)
Net transportation expenses [3]			
Oil and NGLs ($/bbl)	**2.45**	1.43	71
Natural gas ($/mcf)	**0.68**	1.30	(48)
Oil equivalent ($/boe)	**3.54**	6.50	(46)
Operating netback [4]			
Oil and NGLs ($/bbl)	**46.71**	38.05	23
Natural gas ($/mcf)	**0.56**	(1.03)	(154)
Oil equivalent ($/boe)	**18.06**	2.91	521
Depletion and depreciation ($/boe)	**(14.42)**	(15.94)	(10)
General and administrative expenses ($/boe)	**(13.86)**	(46.35)	(70)
Share based compensation ($/boe)	**(10.11)**	(29.10)	(65)
Finance expense ($/boe)	**(1.06)**	(3.18)	(67)
Finance income ($/boe)	**10.60**	27.22	(61)
Unutilized transportation ($/boe)	**(2.49)**	(4.17)	(40)
Net loss ($/boe)	**(13.28)**	(68.61)	(81)

(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, 2024

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, 2024 and the audited financial statements and related notes for the year ended December 31, 2023. 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 north-eastern British Columbia, Canada. The Company trades on the TSX Venture Exchange ("TSXV") under the symbol "CEI".

OIL AND GAS TERMS

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

Liquids

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

Natural Gas

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

Oil Equivalent

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

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

NOTE REGARDING PRODUCT TYPES

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

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

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

NON-GAAP AND OTHER FINANCIAL MEASURES

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

Non-GAAP Financial Measures

Adjusted funds flow (used)
Management uses adjusted funds flow (used) to analyze performance and considers it a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments and abandonment obligations and to repay debt, if any. Adjusted funds flow (used) is a non-GAAP financial measure and has been defined by the Company as cash flow from (used in) operating activities excluding the change in non-cash working capital related to operating activities, 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 (used in) operating activities under the heading "Cash Flow From (Used in) Operating Activities and Adjusted Funds Flow (Used)".

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

	Three Months Ended March 31	
($000s)	**2024**	2023
Transportation expenses	**545**	278
Unutilized transportation	**(225)**	(109)
Net transportation expenses (non-GAAP)	**320**	169

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)	**2024**	2023
Oil and natural gas sales	**3,666**	954
Royalties	**(821)**	(268)
Operating expenses	**(894)**	(441)
Net transportation expenses	**(320)**	(169)
Operating netback (non-GAAP)	**1,631**	76

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)	**2024**	2023
Capital expenditures – property, plant, and equipment	**393**	3,537
Capital expenditures – exploration and evaluation assets	**870**	1,602
Capital expenditures (non-GAAP)	**1,263**	5,139

Capital Management Measures

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

In Q1 2024, Coelacanth continued to make strides on its large Two Rivers Montney project. As noted below, excellent pad results in the Upper and Lower Montney have proven commerciality and we are moving forward with licensing and ordering equipment for the ultimate construction of a battery facility and related pipeline infrastructure to accommodate future growth. The licensing process has gone very well, and we anticipate being on target for construction in Q4 2024 and Q1 2025 for an on-stream date of April 2025. To accommodate future growth, Coelacanth has to date secured long-term gas transportation of 76.5 mmcf/d as well as long-term gas processing of up to 60 mmcf/d.

At Two Rivers East, Coelacanth had previously released a successful pad (5-19) that consisted of three Lower Montney wells and one Basal Montney well. As previously released, test production from the four wells was a combined 4,410 boe/d (55% light oil). (1) Additional 5-19 pad wells have already been licensed and Coelacanth will determine timing of additional drilling once infrastructure is closer to completion.

At Two Rivers West, Coelacanth had previously released a successful pad that consisted of two Upper Montney wells. The C10-08 produced at a restricted rate of 542 boe/d for four months and was then re-tested at an unrestricted rate of 1,284 boe/d (1) for a short duration. Facility restrictions on both water and gas handling will limit production from the 10-08 pad until additional pipelines and facilities can be permitted and constructed. The timing of adding any material production will be longer term given the capital focus on Two Rivers East infrastructure for 2024 but Two Rivers West results show great potential for future development.

Overall, we believe Coelacanth is on track with its Two Rivers project in all aspects and well positioned for long-term growth given achievements to date on the project combined with its financial strength that includes $67.1 million in adjusted working capital (includes $61.9 million cash) on the balance sheet and no debt.

We look forward to reporting updates on the Two Rivers project in the upcoming quarters.

(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)	**2024**	2023	% Change
Oil and natural gas sales	**3,666**	954	284
Cash flow from (used in) operating activities	**3,256**	(2,042)	(259)
Per share - basic and diluted (3)	**0.01**	(-)	100
Adjusted funds flow (used) (1)	**1,078**	(554)	(295)
Per share - basic and diluted	**-**	(-)	-
Net loss	**(1,201)**	(1,789)	(33)
Per share - basic and diluted	**(-)**	(-)	-
Total assets	**186,003**	108,316	72
Total long-term liabilities	**7,604**	8,558	(11)
Adjusted working capital (2)	**67,139**	61,215	10

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

(2) Adjusted working capital 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 increased and net loss decreased in Q1 2024 compared to Q1 2023 due to an increase in oil and natural gas production stemming from two new wells at Two Rivers West placed on production in Q4 2023.

PRODUCTION	**Three Months Ended March 31**		
	2024	2023	% Change
Average Daily Production (1)			
Oil and condensate (bbls/d)	**300**	46	552
Other NGLs (bbls/d)	**37**	14	164
Oil and NGLs (bbls/d)	**337**	60	462
Natural gas (mcf/d)	**3,934**	1,380	185
Oil equivalent (boe/d)	**993**	290	242

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

Daily production increased to 993 boe/d for the three months ended March 31, 2024 from 290 boe/d for the comparative period in 2023. The increase in production was the result of successful drilling at Two Rivers West and the resulting two Upper Montney wells coming on-stream in Q4 2023.

Coelacanth's production profile for the first quarter of 2024 shifted more towards oil and NGLs when compared to the comparative quarter in 2023 as the result of flush oil production from the two wells brought on-stream in Q4 2023. The Q1 2024 weighting was 66% natural gas (Q1 2023 - 79%) and 34% oil and NGLs (Q1 2023 - 21%).

OIL AND NATURAL GAS SALES	**Three Months Ended March 31**		
($000s)	**2024**	2023	% Change
Oil and condensate	**2,334**	390	498
Other NGLs	**116**	54	115
Oil and NGLs	**2,450**	444	452
Natural gas	**1,216**	510	138
Total	**3,666**	954	284
Average Sales Price			
Oil and condensate ($/bbl)	**85.30**	94.78	(10)
Other NGLs ($/bbl)	**34.79**	42.98	(19)
Oil and NGLs ($/bbl)	**79.82**	82.72	(4)
Natural gas production sales and transportation revenue ($/mcf)	**3.40**	4.11	(17)
Combined ($/boe)	**40.57**	36.60	11

Revenue totaled $3.7 million for the three months ended March 31, 2024, up from $1.0 million for the comparative period in 2023 mainly as a result of a large increase in production resulting from the successful drilling at Two Rivers West despite lower commodity prices.

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

Commodity Pricing	**Three Months Ended March 31**		
	2024	2023	% Change
Oil and NGLs			
Corporate price ($CDN/bbl)	**79.82**	82.72	(4)
Canadian light sweet ($CDN/bbl)	**95.45**	99.73	(4)
West Texas Intermediate ("WTI") ($US/bbl)	**76.96**	76.13	1
Natural gas			
Corporate price ($CDN/mcf)	**3.40**	4.11	(17)
AECO price ($CDN/mcf)	**2.18**	3.23	(33)
Westcoast Station 2 ($CDN/mcf)	**2.11**	2.75	(23)
Chicago City Gate ($US/mmbtu)	**2.82**	2.65	6
Exchange rate			
CDN/US dollar exchange rate	**0.7417**	0.7398	-

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 83.6% of Canadian light sweet prices for the three months ended March 31, 2024, consistent with 82.9% for the comparative period in 2023. Coelacanth's liquids mix during the first quarter of 2024 was approximately 89% light oil, condensate and pentanes, 5% butane and 6% propane (Q1 2023 - 77% light oil, condensate and pentanes, 12% butane and 11% propane). The increase in light oil, condensate and pentanes was due to flush oil production at Two Rivers West during Q1 2024.

Corporate average natural gas prices were 89.4% of Chicago City Gate price (converted to Canadian dollars) for the three months ended March 31, 2024, down from 114.7% for the comparative period in 2023. The decrease was due to a higher percentage of the Company's natural gas production being sold under lower priced AECO and Westcoast Station 2 contracts than Chicago contracts. The Company has contracted 1.5 mmcf/d of natural gas to be delivered to Chicago with the remainder being delivered to Westcoast Station 2.

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

ROYALTIES	**Three Months Ended March 31**		
($000s)	**2024**	2023	% Change
Oil and NGLs	**638**	141	352
Natural gas	**183**	127	44
Royalties	**821**	268	206
Average Royalty Rate (% of sales)			
Oil and NGLs	**26.0**	31.8	(18)
Natural gas	**15.0**	24.9	(40)
Combined	**22.4**	28.1	(20)

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 $0.8 million for the three months ended March 31, 2024, up from $0.3 million for the comparative period in 2023 mainly as a result of the significant growth in production and revenue at Two Rivers West. Royalty rates declined as the result of a decrease in oil, NGLs, and natural gas commodity prices and the new wells at Two Rivers West having less royalty burdens than the legacy production.

OPERATING EXPENSES	**Three Months Ended March 31**		
($000s)	**2024**	2023	% Change
Oil and NGLs	**304**	91	234
Natural gas	**590**	350	69
Operating expenses	**894**	441	103
Average operating expenses			
Oil and NGLs ($/bbl)	**9.89**	16.93	(42)
Natural gas ($/mcf)	**1.65**	2.82	(41)
Combined ($/boe)	**9.89**	16.93	(42)

Per unit operating expenses were $9.89/boe for the three months ended March 31, 2024, down from $16.93/boe in the comparative period in 2023. The decrease is mainly the result of increased production at Two Rivers West, thus spreading fixed costs at the Two Rivers facility over more production volumes.

NET TRANSPORTATION EXPENSES	Three Months Ended March 31		
($000s)	**2024**	2023	% Change
Oil and NGLs	**75**	8	838
Natural gas	**245**	161	52
Net transportation expenses (non-GAAP)	**320**	169	89
Unutilized transportation	**225**	109	106
Transportation expenses	**545**	278	96
Average transportation expenses			
Oil and NGLs ($/bbl)	**2.45**	1.43	71
Natural gas ($/mcf)	**0.68**	1.30	(48)
Net transportation expenses ($/boe)	**3.54**	6.50	(46)
Unutilized transportation ($/boe)	**2.49**	4.17	(40)
Transportation expenses ($/boe)	**6.03**	10.67	(43)

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.

Net transportation expenses decreased on a per boe basis to $3.54/boe for the three months ended March 31, 2024, compared to $6.50/boe for the comparative period in 2023. Over this period net transportation expenses for oil and NGLs on a per boe basis increased with flush oil production from Two Rivers West which has higher net transportation costs than NGLs. The decrease for natural gas was the result of production exceeding 1.5 mmcf/d (portion being delivered to Chicago with a higher net transportation expense) and thus a higher percentage of natural gas sales in Q1 2024 being sold under AECO and Westcoast Station 2 contracts instead of Chicago. While the sales prices were higher on Chicago contracts than on AECO and Westcoast Station 2 contracts, the net transportation expenses are also higher.

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.

OPERATING NETBACK	Three Months Ended March 31		
	2024	2023	% Change
Oil and NGLs ($/bbl)			
Revenue	**79.82**	82.72	(4)
Royalties	**(20.77)**	(26.31)	(21)
Operating expenses	**(9.89)**	(16.93)	(42)
Net transportation expenses (non-GAAP)	**(2.45)**	(1.43)	71
Operating netback (non-GAAP)	**46.71**	38.05	23
Natural gas ($/mcf)			
Revenue	**3.40**	4.11	(17)
Royalties	**(0.51)**	(1.02)	(50)
Operating expenses	**(1.65)**	(2.82)	(41)
Net transportation expenses (non-GAAP)	**(0.68)**	(1.30)	(48)
Operating netback (loss) (non-GAAP)	**0.56**	(1.03)	(154)
Combined ($/boe)			
Revenue	**40.57**	36.60	11
Royalties	**(9.08)**	(10.26)	(12)
Operating expenses	**(9.89)**	(16.93)	(42)
Net transportation expenses (non-GAAP)	**(3.54)**	(6.50)	(46)
Operating netback (non-GAAP)	**18.06**	2.91	521

During the three months ended March 31, 2024, Coelacanth generated an operating netback (see "Non-GAAP and Other Financial Measures") of $18.06/boe, up from $2.91/boe for the comparative period in 2023 as the result of new wells at Two Rivers West which were less burdened by royalties than legacy production and had reduced operating expenses per unit as facility fixed costs were spread over increased production volumes.

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)	**2024**	2023	% Change
Operating netback	**18.06**	2.91	521
Depletion and depreciation	**(14.42)**	(15.94)	(10)
General and administrative expenses	**(13.86)**	(46.35)	(70)
Share based compensation	**(10.11)**	(29.10)	(65)
Finance expense	**(1.06)**	(3.18)	(67)
Finance income	**10.60**	27.22	(61)
Unutilized transportation	**(2.49)**	(4.17)	(40)
Net loss	**(13.28)**	(68.61)	(81)

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

	Three Months Ended March 31		
($000s)	**2024**	2023	% Change
Operating netback	**1,631**	76	2,046
Depletion and depreciation	**(1,303)**	(415)	214
General and administrative expenses	**(1,252)**	(1,208)	4
Share based compensation	**(913)**	(759)	20
Finance expense	**(96)**	(83)	16
Finance income	**957**	709	35
Unutilized transportation	**(225)**	(109)	106
Net loss	**(1,201)**	(1,789)	(33)

DEPLETION AND DEPRECIATION	Three Months Ended March 31		
	2024	2023	% Change
Depletion and depreciation ($000s)	**1,303**	415	214
Depletion and depreciation ($/boe)	**14.42**	15.94	(10)

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, 2024 increased to $1.3 million from $0.4 million for the comparative period in 2023 as a result of increased production. On a per boe basis, depletion and depreciation for the three months ended March 31, 2024 was $14.42/boe, consistent with $15.94/boe for the comparative period in 2023.

Included in depletion and depreciation expense for the three months ended March 31, 2024 is $0.1 million (March 31, 2023 - $51 thousand) related to the right-of-use assets for the Company's head office lease and field equipment.

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

At March 31, 2024 and March 31, 2023, 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, 2024 and March 31, 2023, 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		
($000s)	**2024**	2023	% Change
G&A expenses (gross)	**1,286**	1,280	-
G&A capitalized	**(34)**	(72)	(53)
G&A expenses (net)	**1,252**	1,208	4
G&A expenses ($/boe)	**13.86**	46.35	(70)

Net general and administrative expenses ("G&A") totaled $1.3 million for the three months ended March 31, 2024, consistent with $1.2 million for the comparative period in 2023.

On a per unit basis G&A decreased to $13.86/boe for the three months ended March 31, 2024 compared to $46.35/boe for the comparative period in 2023 due to the increase in production.

SHARE BASED COMPENSATION

($000s)	Three Months Ended March 31 **2024**	2023	% Change
Share based compensation (gross)	**1,028**	1,013	1
Share based compensation (capitalized)	**(115)**	(254)	(55)
Share based compensation (net)	**913**	759	20
Share based compensation ($/boe)	**10.11**	29.10	(65)

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 $0.9 million for the three months ended March 31, 2024 compared to $0.8 million for the comparative period in 2023 due to a lower capitalization rate in Q1 2024.

FINANCE EXPENSE

	Three Months Ended March 31 **2024**	2023	% Change
Interest expense	**33**	22	50
Accretion of decommissioning obligations	**63**	61	3
Finance expense	**96**	83	16
Finance expense ($/boe)	**1.06**	3.18	(67)

Accretion expense was consistent for the three months ended March 31, 2024 compared to the same period in 2023. Interest expense relates mainly to interest on lease obligations and outstanding letters of guarantee for firm transportation agreements and decommissioning obligations. The increase stems from increased interest rates and the addition of a new field equipment lease.

FINANCE INCOME

Finance income relates to interest earned on cash in the bank. Finance income totaled $1.0 million for the three months ended March 31, 2024 compared to $0.7 million for the comparative period in 2023. The increase corresponds to the increase in the Company's cash balance over the comparative period due to common share financings in Q4 2023.

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, 2024 total approximately $178.6 million (December 31, 2023 - $177.6 million).

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

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

($000s)	Three Months Ended March 31 **2024**	2023	% Change
Cash flow from (used in) operating activities	**3,256**	(2,042)	(259)
Add (deduct):			
Decommissioning expenditures	**148**	542	(73)
Restricted cash deposits	**424**	453	(6)
Change in non-cash working capital	**(2,750)**	493	(658)
Adjusted funds flow (used) (non-GAAP)	**1,078**	(554)	(295)

Adjusted funds flow (see "Non-GAAP and Other Financial Measures") was $1.1 million ($nil per basic and diluted share) for the three months ended March 31, 2024 and adjusted funds used was $0.6 million ($nil per basic and diluted share) for the comparative period in 2023. The large increase was a result of flush production from new wells placed on-stream at Two Rivers West in Q4 2023.

Cash flow from operating activities for the three months ended March 31, 2024 was $3.3 million ($0.01 per basic and diluted share) and cash flow used in operating activities was $2.0 million ($nil per basic and diluted share) for the comparative period in 2023. Cash flow from (used in) 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 increase in cash flow from operating activities for the three months ended March 31, 2024 compared to Q1 2023 was mainly the result of flush production from new wells placed on-stream at Two Rivers West in Q4 2023, decreased decommissioning expenditures, and increased changes in non-cash working capital.

NET LOSS

The Company incurred a net loss of $1.2 million ($nil per basic and diluted share) for the three months ended March 31, 2024, down from $1.8 million ($nil per basic and diluted share) for the comparative period in 2023 due to an increase in oil and natural gas production stemming from two new wells at Two Rivers West placed on production in Q4 2023.

CAPITAL EXPENDITURES	Three Months Ended March 31		
($000s)	**2024**	2023	% Change
Land	**241**	314	(23)
Drilling, completions, and workovers	**121**	1,865	(94)
Equipment	**879**	2,880	(69)
Geological and geophysical	**22**	80	(73)
Total expenditures	**1,263**	5,139	(75)

During the three months ended March 31, 2024, the Company continued with facility procurement at Two Rivers East.

During the three months ended March 31, 2023, the Company prepared for pad drilling at Two Rivers by spending on preliminary facility upgrades and purchasing casing inventory.

LIQUIDITY AND CAPITAL RESOURCES

Management uses adjusted working capital (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, 2024**	December 31, 2023	% Change
Current assets	**64,539**	87,616	(26)
Less:			
Current liabilities	**(6,053)**	(28,754)	(79)
Working capital	**58,486**	58,862	(1)
Add:			
Restricted cash deposits	**6,784**	6,784	-
Current portion of decommissioning obligations	**1,869**	1,943	(4)
Adjusted working capital (Capital management measure)	**67,139**	67,589	(1)

At March 31, 2024, the Company had adjusted working capital of $67.1 million.

On November 15, 2023, the Company closed a bought-deal public financing through a syndicate of underwriters. The Company issued 100.0 million units of the Company (“Units”) at a price of $0.80 per Unit for gross proceeds of $80.0 million. A Unit is comprised of one common share of the Company and 0.33 common share purchase warrants. Each whole common share purchase warrant entitles the holder to purchase one common share at an exercise price of $1.05 per common share expiring on November 15, 2024.

On November 16, 2023, the Company closed a non-brokered private placement to three employees of 1,875,000 units of the Company ("Private Placement Units"), at a price of $0.80 per Private Placement Unit, for aggregate proceeds of $1.5 million. Each Private Placement Unit consists of one common share of the Company and one common share purchase warrant. Each common share purchase warrant entitles the holder to purchase one common share of the Company at a price of $0.80 per share expiring on November 16, 2028.

Management anticipates that the Company will continue to have adequate liquidity to fund budgeted capital investments and commitments through a combination of its cash balance, cash flow, equity, and debt if required. 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:

($000s)	**Total**	**Less than One Year**	**One to Three Years**	**After Three Years**
Accounts payable and accrued liabilities	3,737	3,737	-	-
Lease obligations	1,125	447	590	88
Decommissioning obligations	8,795	1,869	593	6,333
Operating commitments	711	194	388	129
Firm transportation agreements	135,643	4,502	10,536	120,605
Property, plant, and equipment	9,941	9,941	-	-
Total contractual obligations	159,952	20,690	12,107	127,155

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, 2025.
- 10.0 mmcf/d to deliver natural gas to Westcoast Station 2 from January 1, 2023 through December 31, 2037.
- 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.

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, 2025.
- 10.0 mmcf/d to deliver natural gas to Westcoast Station 2 from June 1, 2023 through May 31, 2025.
- 17.7 mmcf/d to deliver natural gas to Westcoast Station 2 from June 1, 2023 through May 31, 2024.
- 20.0 mmcf/d to deliver natural gas to Westcoast Station 2 from October 1, 2023 through October 31, 2026.

Subsequent to March 31, 2024, the Company entered into the following firm transportation commitments:

- 15.0 mmcf/d to deliver natural gas to Westcoast Station 2 from May 1, 2024 through April 30, 2055.
- extended the assignment to a third party for 10.0 mmcf/d to deliver natural gas to Westcoast Station 2 from May 31, 2025 as noted above through December 31, 2027.
- assigned an additional 10.0 mmcf/d to a third party to deliver natural gas to Westcoast Station 2 from November 1, 2024 through December 31, 2025.

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

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 field equipment 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, 2024**	May 28, 2024
Voting common shares	**529,392**	529,392
Warrants	**62,710**	62,710
Stock options	**18,736**	18,736
Restricted share units	**7,327**	7,327
Total	**618,165**	618,165

SUMMARY OF QUARTERLY RESULTS

	Q1 2024	Q4 2023	Q3 2023	Q2 2023	Q1 2023	Q4 2022	Q3 2022	Q2 2022
Average Daily Production								
Oil and NGLs (bbls/d)	**337**	447	46	67	60	70	73	86
Natural gas (mcf/d)	**3,934**	2,858	929	1,321	1,380	1,468	1,567	1,676
Oil equivalent (boe/d)	**993**	923	201	287	290	315	334	365
($000s, except per share amounts)								
Oil and natural gas sales	**3,666**	4,204	679	826	954	1,676	2,135	2,334
Cash flow from (used in)								
operating activities	**3,256**	(404)	(2,553)	765	(2,042)	(636)	(6,732)	(1,713)
Per share basic and diluted (2)	**0.01**	(-)	(0.01)	(-)	(-)	(-)	(0.02)	(0.01)
Adjusted funds flow (used) (1)	**1,078**	1,750	(773)	(756)	(554)	(60)	161	22
Per share basic and diluted	**-**	-	(-)	(-)	(-)	(-)	-	-
Net loss	**(1,201)**	(750)	(1,869)	(2,165)	(1,789)	(725)	(830)	(8,062)
Per share basic and diluted	**(-)**	(-)	(-)	(0.01)	(-)	(-)	(-)	(0.03)

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

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

The Company experienced normal production declines from flush production for the Two Rivers property from Q2 2022 to Q3 2023. The increase in production, oil and natural gas sales, cash flow from operating activities, and adjusted funds flow in Q4 2023 and Q1 2024 stems from two new wells at Two Rivers West coming on-stream in Q4 2023. 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. In Q3 2022 cash flow used in operating activities increased due to moving $8.1 million of cash to restricted cash deposits for security on letters of credit relating to firm transportation agreements and decommissioning obligations. Q2 and Q3 2022 oil and natural gas sales increased due to rising commodity prices. In Q2 2022 the net loss increased due to the Company incurring accelerated share based compensation expense of $3.3 million on Leucrotta Exploration Inc. stock options and RSUs that vested in conjunction with the arrangement and a share compensation charge of $4.5 million relating to private placements of Coelacanth.

MATERIAL ACCOUNTING POLICIES

All accounting policies are consistent with those of the previous financial year, except as noted below. Refer to note 3 of the audited financial statements for the year ended December 31, 2023 for the Company's material accounting policies.

IAS 1 Presentation of Financial Statements was amended in January 2020 and October 2022 by the IASB to clarify the presentation requirements of liabilities as either current or non-current within the statement of financial position. The amendments apply retrospectively for annual reporting periods beginning on or after January 1, 2024. The Company adopted these amendments effective January 1, 2024 and the adoption did not have an impact on the Company's condensed interim 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, 2023 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 fluctuations, the uncertainty of replacing production and reserves on an economic basis, government regulations, 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 abilities to acquire suitable prospects or properties and discover new reserves.

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

Operational risks

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

Market risk

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

Foreign exchange risk

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

Interest rate risk
The Company is exposed to interest rate risk on its cash and restricted cash deposit 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 Company does not currently have a credit facility.

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, 2024, $1.4 million (98%) of the Company's outstanding accounts receivable were current and $35 thousand (2%) were outstanding for more than 90 days. During the three months ended March 31, 2024, the Company deemed $9 thousand of outstanding accounts receivable to be uncollectable (March 31, 2023 - $10 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. In managing liquidity risk, the Company ensures that it has access to additional financing, including potential equity issuances and additional debt financing. The Company also mitigates liquidity risk by maintaining an insurance program to minimize exposure to insurable losses.

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, 2023, 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 2024	Q4 2023	Q3 2023	Q2 2023	Q1 2023	Q4 2022	Q3 2022	Q2 2022
Condensate (bbls/d)	**19**	12	4	6	8	6	9	9
Other NGLs (bbls/d)	**37**	28	7	14	14	15	19	16
NGLs (bbls/d)	**56**	40	11	20	22	21	28	25
Tight oil (bbls/d)	**281**	407	35	47	38	49	45	61
Condensate (bbls/d)	**19**	12	4	6	8	6	9	9
Oil and condensate (bbls/d)	**300**	419	39	53	46	55	54	70
Other NGLs (bbls/d)	**37**	28	7	14	14	15	19	16
Oil and NGLs (bbls/d)	**337**	447	46	67	60	70	73	86
Shale gas (mcf/d)	**3,934**	2,858	929	1,321	1,380	1,468	1,567	1,676
Natural gas (mcf/d)	**3,934**	2,858	929	1,321	1,380	1,468	1,567	1,676
Oil equivalent (boe/d)	**993**	923	201	287	290	315	334	365

TEST RESULTS AND INITIAL PRODUCTION RATES

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 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.

For the short-term production test of the C10-08 Upper Montney well in February 2024, the well was production tested for 2 days and produced at an average rate of 359 bbl/d oil and 5,236 mcf/d gas (net of load fluid and energizing fluid) over that period. This was an inline test to prove deliverability after four months of production. At the end of the test, flowing wellhead pressure and production rates were stable.

A pressure transient analysis or well-test interpretation has not been carried out on these five 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 2024**	December 31 2023
Assets			
Current assets			
Cash		**61,858**	82,568
Current portion of restricted cash deposits	(4)	**916**	492
Accounts receivable		**1,460**	4,139
Prepaid expenses and deposits		**305**	417
		64,539	87,616
Restricted cash deposits	(4)	**6,784**	6,784
Property, plant, and equipment	(5)	**44,874**	45,711
Exploration and evaluation assets	(6)	**69,806**	68,883
		121,464	121,378
		186,003	208,994
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities		**3,737**	26,376
Current portion of lease obligations	(7)	**447**	435
Current portion of decommissioning obligations	(8)	**1,869**	1,943
		6,053	28,754
Lease obligations	(7)	**678**	795
Decommissioning obligations	(8)	**6,926**	6,926
		13,657	36,475
Shareholders' Equity			
Shareholders' capital	(9)	**174,482**	173,918
Warrants	(9)	**6,562**	6,562
Contributed surplus		**4,583**	4,119
Deficit		**(13,281)**	(12,080)
		172,346	172,519
		186,003	208,994
Commitments	(16)		
Subsequent events	(16)		

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 2024	2023
Revenue			
Oil and natural gas sales	(15)	**3,666**	954
Royalties		**(821)**	(268)
		2,845	686
Expenses			
Operating		**894**	441
Transportation		**545**	278
Depletion and depreciation	(5)	**1,303**	415
General and administrative		**1,252**	1,208
Share based compensation	(10)	**913**	759
Finance income		**(957)**	(709)
Finance expense		**96**	83
		4,046	2,475
Net loss and comprehensive loss		**(1,201)**	(1,789)
Net loss per share			
Basic and diluted	(11)	**(-)**	(-)

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, 2022		97,259	4,272	1,053	(5,507)	97,077
Net loss		-	-	-	(1,789)	(1,789)
Exercise of warrants		119	(44)	-	-	75
Share based compensation	(10)	-	-	1,013	-	1,013
Balance, March 31, 2023		97,378	4,228	2,066	(7,296)	96,376
Balance, December 31, 2023		**173,918**	**6,562**	**4,119**	**(12,080)**	**172,519**
Net loss		**-**	**-**	**-**	**(1,201)**	**(1,201)**
Settlement of vested RSUs	(9)	**564**	**-**	**(564)**	**-**	**-**
Share based compensation	(10)	**-**	**-**	**1,028**	**-**	**1,028**
Balance, March 31, 2024		**174,482**	**6,562**	**4,583**	**(13,281)**	**172,346**

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

Coelacanth Energy Inc.
Condensed Interim Statements of Cash Flows

(unaudited) ($000s)	Note	Three Months Ended March 31 **2024**	2023
Operating Activities			
Net loss		**(1,201)**	(1,789)
Depletion and depreciation	(5)	**1,303**	415
Share based compensation	(10)	**913**	759
Finance expense		**96**	83
Interest paid		**(33)**	(22)
Decommissioning expenditures	(8)	**(148)**	(542)
Restricted cash deposits	(4)	**(424)**	(453)
Change in non-cash working capital	(14)	**2,750**	(493)
		3,256	(2,042)
Financing Activities			
Exercise of warrants		**-**	75
Payment of lease obligations	(7)	**(105)**	(47)
Change in non-cash working capital	(14)	**(273)**	-
		(378)	28
Investing Activities			
Capital expenditures - property, plant, and equipment	(5)	**(393)**	(3,537)
Capital expenditures - exploration and evaluation assets	(6)	**(870)**	(1,602)
Change in non-cash working capital	(14)	**(22,325)**	(4,262)
		(23,588)	(9,401)
Change in cash		**(20,710)**	(11,415)
Cash, beginning of period		**82,568**	65,410
Cash, end of period		**61,858**	53,995

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

1. REPORTING ENTITY

Coelacanth Energy Inc. ("Coelacanth" or the "Company") is an oil and natural gas company, actively engaged in the acquisition, development, exploration, and production of oil and natural gas reserves in north-eastern 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, 2023.

Certain comparative amounts in the statement of financial position and statement of shareholders' equity have been adjusted to conform with the current period presentation. Specifically, the Reserve from common-control transaction of $(18,063) that was previously presented as its own account has been re-presented to be reflected as a reduction of Shareholders' capital. There were no changes to the operating results, cash flows or financial position of the Company as a result of this presentation change.

The condensed interim financial statements were authorized for issuance by the Board of Directors on May 28, 2024.

(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, 2023.

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, 2023, except as noted below. The accounting policies have been applied consistently by the Company to all periods presented in these condensed interim financial statements.

IAS 1 Presentation of Financial Statements was amended in January 2020 and October 2022 by the IASB to clarify the presentation requirements of liabilities as either current or non-current within the statement of financial position. The amendments apply retrospectively for annual reporting periods beginning on or after January 1, 2024. The Company adopted these amendments effective January 1, 2024 and the adoption did not have an impact on the Company's condensed interim financial statements.

4. RESTRICTED CASH DEPOSITS

The Company has $7.7 million in restricted guaranteed investment certificates ("GIC's") with a Canadian chartered bank. These restricted GIC's are being held as security for $7.7 million of letters of guarantee to third parties relating primarily to firm transportation agreements and decommissioning obligations. Restricted cash deposits will be released as letters of guarantee are lowered as a result of settlements of decommissioning obligations or if the restricted GIC's are replaced by a credit facility.

	March 31, 2024	December 31, 2023
Current	**916**	492
Long-term	**6,784**	6,784
	7,700	7,276

5. PROPERTY, PLANT, AND EQUIPMENT

Cost	**Total**
Balance, December 31, 2023	94,783
Additions	**393**
Capitalized share based compensation	**62**
Change in decommissioning obligation estimates (note 8)	**11**
Balance, March 31, 2024	**95,249**

Accumulated Depletion, Depreciation, and Impairment	**Total**
Balance, December 31, 2023	49,072
Depletion and depreciation	**1,303**
Balance, March 31, 2024	**50,375**

Net Book Value	**Total**
December 31, 2023	45,711
March 31, 2024	**44,874**

During the three months ended March 31, 2024, approximately $17 thousand (March 31, 2023 - $31 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, 2024 included an estimated $19.4 million (March 31, 2023 - $38.5 million) for forecasted future development costs associated with proved and probable undeveloped oil and natural gas reserves and excluded approximately $1.2 million (March 31, 2023 - $1.2 million) for the estimated salvage value of production equipment and facilities. Depletion expense on development and production assets was $1.2 million for the three months ended March 31, 2024 (March 31, 2023 - $0.3 million).

Included in depletion and depreciation expense for the three months ended March 31, 2024, is $22 thousand (March 31, 2023 - $22 thousand) related to the right-of-use asset for the Company’s head office lease. At March 31, 2024, the net book value of this right-of-use asset is $0.3 million (December 31, 2023 - $0.3 million).

Included in depletion and depreciation expense for the three months ended March 31, 2024, is $87 thousand (March 31, 2023 - $29 thousand) related to the right-of-use asset for field equipment. At March 31, 2024, the net book value of this right-of-use asset is $0.7 million (December 31, 2023 - $0.7 million).

Impairment assessment

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

6. EXPLORATION AND EVALUATION ASSETS

	Total
Balance, December 31, 2023	68,883
Additions	**870**
Capitalized share based compensation	**53**
Balance, March 31, 2024	**69,806**

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, 2024 is approximately $51.1 million relating to pad drilling and completions and preliminary facility construction costs related to the Company’s Two Rivers East project (December 31, 2023 - $50.1 million).

During the three months ended March 31, 2024, approximately $17 thousand (March 31, 2023 - $41 thousand) of directly attributable general and administrative costs were capitalized as expenditures on E&E assets.

At March 31, 2024, 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. LEASE OBLIGATIONS

The Company has the following leases in place as at March 31, 2024:

- 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.
- Field equipment lease commencing March 1, 2023 expiring February 28, 2026. The lease obligation is discounted with an effective interest rate of 10.0% and the right-of-use asset is amortized based on the lease term.

	Total
Balance, December 31, 2023	1,230
Lease payments	**(130)**
Interest expense	**25**
Balance, March 31, 2024	**1,125**
Current	**447**
Long-term	**678**
	1,125

The total undiscounted amount of the estimated future cash flows to settle the lease obligations over the remaining lease terms is $1.2 million. The Company's minimum lease payments are as follows:

	March 31, 2024
Within one year	522
Later than one year but not later than three years	632
Later than three years	90
Minimum lease payments	1,244
Amount representing interest expense	(119)
Present value of net lease payments	**1,125**

8. DECOMMISSIONING OBLIGATIONS

The Company's decommissioning obligations result from its ownership interest in development and production assets including well sites and gathering systems. The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to abandon and reclaim the wells and facilities, and the estimated timing of the costs to be incurred in future periods. The total undiscounted amount of the estimated cash flows, adjusted for inflation at 1.87% per year (December 31, 2023 - 1.65%) required to settle the decommissioning obligations is approximately $13.7 million (December 31, 2023 - $13.3 million) which is estimated to be incurred over the next 34 years. At March 31, 2024, a risk-free rate of 3.37% (December 31, 2023 – 3.05%) was used to calculate the net present value of the decommissioning obligations.

	Three Months Ended March 31, 2024	Year Ended December 31, 2023
Balance, beginning of period	**8,869**	8,913
Provisions incurred	**-**	971
Provisions settled	**(148)**	(1,883)
Revisions in estimated cash flows	**-**	746
Revisions due to change of rates	**11**	(141)
Accretion	**63**	263
Balance, end of period	**8,795**	8,869
Current	**1,869**	1,943
Long-term	**6,926**	6,926
	8,795	8,869

9. SHAREHOLDERS' CAPITAL AND WARRANTS

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

Voting Common Shares	**Number**	**Amount**
Balance, December 31, 2023	528,650	173,918
Settlement of restricted share units	**742**	**564**
Balance, March 31, 2024	**529,392**	**174,482**

In connection with the arrangement on May 31, 2022, involving Coelacanth, Leucrotta Exploration Inc. ("Leucrotta") and Vermilion Energy Inc., the reserve created from the common-control transaction of $(18,063) represented the difference between the fair value of the Coelacanth shares issued to existing Leucrotta shareholders and the net book value of the acquired assets and assumed liabilities, and has been presented as a reduction against Shareholders' Capital. Prior period comparative amounts have been re-presented to reflect this change.

Warrants	**Number**	**Amount**
Balance, December 31, 2023 and March 31, 2024	**62,710**	**6,562**

The following table summarizes the warrants outstanding and exercisable at March 31, 2024:

Issue Date	**Expiry Date**	**Exercise Price**	**Number**
June 10, 2022	June 10, 2027	$0.27	27,502
November 15, 2023	November 15, 2024	$1.05	33,333
November 16, 2023	November 16, 2028	$0.80	1,875
			62,710

10. SHARE BASED COMPENSATION PLANS

Stock options

The Company has authorized and reserved for issuance 52.9 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, 2024, 18.7 million options were outstanding at an average exercise price of $0.72 per share.

	Number of Options	**Weighted Average Exercise Price ($)**
Balance, December 31, 2023	13,249	0.68
Granted	**5,487**	**0.80**
Balance, March 31, 2024	**18,736**	**0.72**
Exercisable, March 31, 2024	**3,572**	**0.65**

The following table summarizes the stock options outstanding and exercisable at March 31, 2024:

		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	5,379	3.3	0.55	1,802	0.54
$0.71 to $0.79	5,112	3.8	0.75	1,770	0.76
$0.80 to $0.83	8,245	4.8	0.80	-	-
	18,736	4.1	0.72	3,572	0.65

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, 2024	December 31, 2023
Risk-free interest rate (%)	**3.8**	3.4
Expected life (years)	**4.0**	4.0
Expected volatility (%)	**65.2**	67.4
Expected dividend yield (%)	**-**	-
Forfeiture rate (%)	**4.7**	3.1
Weighted average fair value of options granted ($ per option)	**0.42**	0.41

During the three months ended March 31, 2024, the Company recognized $0.5 million (March 31, 2023 - $0.5 million) of share based compensation related to the stock options of which $0.4 million was recognized as an expense and $61 thousand was capitalized (March 31, 2023 - $0.4 million was recognized as an expense and $0.1 million was capitalized). At March 31, 2024, there was $3.8 million remaining as unrecognized share based compensation related to the stock options.

Restricted share units

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

	Number of RSUs
Balance, December 31, 2023	5,380
Granted	**2,689**
Exercised	**(742)**
Balance, March 31, 2024	**7,327**
Exercisable, March 31, 2024	**-**

The weighted average market price of the Company's common shares used to value the RSUs granted during the three months ended March 31, 2024 was $0.80 (March 31, 2023 - $0.76). During the three months ended March 31, 2024, the Company recognized $0.5 million (March 31, 2023 - $0.5 million) of share based compensation related to the RSUs of which $0.4 million was recognized as an expense and $54 thousand was capitalized (March 31, 2023 - $0.4 million was recognized as an expense and $0.1 million was capitalized). At March 31, 2024, 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.

11. 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	
	2024	2023
Weighted average number of shares - basic	**529,196**	425,116
Dilutive effect of share based compensation plans	**-**	-
Weighted average number of shares - diluted	**529,196**	425,116

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.

For the three months ended March 31, 2023, 11.0 million stock options, 5.5 million RSUs, and 27.5 million warrants were excluded from the weighted-average share calculation because they were anti-dilutive due to the net loss.

12. FINANCIAL RISK MANAGEMENT

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

Market risk

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

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

Interest rate risk
The Company is exposed to interest rate risk on its cash and restricted cash deposit 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 Company does not currently have a credit facility.

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, 2024.

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, 2024, $1.4 million (98%) of the Company's outstanding accounts receivable were current and $35 thousand (2%) were outstanding for more than 90 days. During the three months ended March 31, 2024, the Company deemed $9 thousand of outstanding accounts receivable to be uncollectable (March 31, 2023 - $10 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. In managing liquidity risk, the Company ensures that it has access to additional financing, including potential equity issuances and additional debt financing. The Company also mitigates liquidity risk by maintaining an insurance program to minimize exposure to insurable losses.

See note 16 for a summary of contractual commitments at March 31, 2024. The Company's accounts payable and accrued liabilities and current portion of lease obligations are all due within the current operating period and the Company's cash balance is sufficient to discharge its current liabilities and commitments due within the upcoming year.

13. CAPITAL MANAGEMENT

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

The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying assets. The Company considers its capital structure to include shareholders' equity and adjusted working capital. Adjusted working capital 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, 2024	December 31, 2023
Shareholders' equity	**172,346**	172,519
Adjusted working capital	**67,139**	67,589

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

($000s)	**March 31, 2024**	December 31, 2023
Current assets	**64,539**	87,616
Less:		
Current liabilities	**(6,053)**	(28,754)
Working capital	**58,486**	58,862
Add:		
Restricted cash deposits	**6,784**	6,784
Current portion of decommissioning obligations	**1,869**	1,943
Adjusted working capital	**67,139**	67,589

In addition, management prepares annual, quarterly, and monthly budgets, which are updated depending on varying factors such as general market conditions and successful capital deployment. The Company's share capital is not subject to external restrictions.

14. SUPPLEMENTAL CASH FLOW INFORMATION

	March 31, 2024	March 31, 2023
Accounts receivable	**2,679**	415
Prepaid expenses and deposits	**112**	100
Accounts payable and accrued liabilities	**(22,639)**	(5,270)
Change in non-cash working capital	**(19,848)**	(4,755)
Relating to:		
Operating	**2,750**	(493)
Financing	**(273)**	-
Investing	**(22,325)**	(4,262)
Change in non-cash working capital	**(19,848)**	(4,755)

15. REVENUE

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

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

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

	Three Months Ended March 31	
	2024	2023
Oil and condensate	**2,334**	390
Other natural gas liquids	**116**	54
Natural gas	**1,216**	510
Total revenue	**3,666**	954

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	
	2024	2023
Natural gas production sales	**975**	350
Transportation revenue	**241**	160
Natural gas sales	**1,216**	510

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 93% for the three months ended March 31, 2024 (March 31, 2023 - two customers represented combined sales of 86%).

16. COMMITMENTS

The following is a summary of the Company's contractual obligations and commitments:

	2024	2025	2026	2027	2028	Thereafter	Total
Operating commitments	145	194	194	178	-	-	711
Firm transportation agreements	3,344	4,333	5,404	7,270	8,387	106,905	135,643
Property, plant, and equipment	7,826	2,115	-	-	-	-	9,941
	11,315	6,642	5,598	7,448	8,387	106,905	146,295

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, 2025.
- 10.0 mmcf/d to deliver natural gas to Westcoast Station 2 from January 1, 2023 through December 31, 2037.
- 50.0 mmcf/d to deliver natural gas to Westcoast Station 2 from June 1, 2023 through May 31, 2038.

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, 2025.
- 10.0 mmcf/d to deliver natural gas to Westcoast Station 2 from June 1, 2023 through May 31, 2025.
- 17.7 mmcf/d to deliver natural gas to Westcoast Station 2 from June 1, 2023 through May 31, 2024.
- 20.0 mmcf/d to deliver natural gas to Westcoast Station 2 from October 1, 2023 through October 31, 2026.

Subsequent to March 31, 2024, the Company entered into the following firm transportation commitments:

- 15.0 mmcf/d to deliver natural gas to Westcoast Station 2 from May 1, 2024 through April 30, 2055.
- extended the assignment to a third party for 10.0 mmcf/d to deliver natural gas to Westcoast Station 2 from May 31, 2025 as noted above through December 31, 2027.
- assigned an additional 10.0 mmcf/d to a third party to deliver natural gas to Westcoast Station 2 from November 1, 2024 through December 31, 2025.

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

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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.