International exploration & production

Management's Discussion & Analysis

Three and nine months ended

December 31, 2024 and 2023

BENGAL ENERGY LTD.

The following Management's Discussion and Analysis ("MD&A") of the consolidated financial results of Bengal Energy Ltd. ("Bengal" or the "Company") is at and for the three and nine months ended December 31, 2024. This MD&A dated February 6, 2025, should be read in conjunction with the Company's unaudited interim condensed consolidated financial statements and related notes for the quarter ended December 31, 2024. The condensed consolidated financial statements of the Company have been prepared in accordance with International Accounting Standard No.34, Interim Financial Reporting ("IAS 34"). These accompanying condensed consolidated financial statements have not been reviewed by the Company's independent auditors.

The functional currency of the Company's operating subsidiary, Bengal Energy (Australia) Pty Ltd. ("Bengal Australia"), is the Australian dollar; the functional currency of the Company is the Canadian dollar ("CAD"). The Company's presentation currency is the CAD. In this MD&A, all dollar amounts are expressed in CAD unless otherwise noted.

This MD&A contains non-IFRS measures, abbreviations and forward-looking information relating to future events and the Company's future performance. Please refer to "*Non-IFRS Measurements*", "*Abbreviations*" and "*Advisories*" sections at the end of this MD&A for further information. Additional information relating to Bengal, including Bengal's audited March 31, 2024, consolidated financial statements and other filings are available on SEDAR at www.sedarplus.ca. In the following discussion, the three months ended December 31, 2024, may be referred to as "third quarter of fiscal 2025", "Q3 fiscal 2025", "current quarter", and "the quarter". The comparative three months ended December 31, 2023, may be referred to as "third quarter of fiscal 2024", "Q3 fiscal 2024".

THIRD QUARTER 2025 SUMMARY

Financial summary:

- **Sales revenue** – Crude oil sales revenue was $1.4 million in the third quarter of fiscal 2025, 11% lower than $1.6 million in Q3 fiscal 2024. Oil lifted was 22% lower in Q3 fiscal 2025 at 124 bbl/d compared to 174 bbl/d in Q3 fiscal 2024. The decreased volume was partially offset by a 25% increase in realized oil prices. More than half of the volumes in the third quarter of fiscal 2025 were sold in October at US$79.53/bbl, which coupled with a stronger US dollar relative to the Canadian dollar, resulted in higher realized prices.
- **Funds from operations**[1] – Funds from operations was $23 thousand during the third quarter of fiscal 2025 compared to funds used in operations of $143 thousand in Q3 fiscal 2024, helped by lower royalties and operating expenses.
- **Net loss** – Bengal reported a net loss of $0.4 million in the third quarter of fiscal 2025 compared to net loss of $0.5 million in the third quarter of fiscal 2024, the decrease in net loss was due to lower royalties, operating and G&A costs more than offsetting the decline in revenue.

Operational summary:

- **Production volumes** – The Company's share of total Cuisinier production in the current quarter was 11,420 bbls (124 bbl/d), a decrease of 29% compared to production of 16,013 bbls (174 bbl/d) in the third quarter of fiscal 2024. The Company continues to investigate the material change in production allocation provided by the Cuisinier operator. Bengal has requested field support to clarify the nature of the change in allocation and is awaiting further information from the operator.
- **Capital expenditures** – Capital activity was limited as Bengal has delayed its capital programs subject to the availability of financing.

[1] See "Non-IFRS and Other Financial Measures" on page 13 of this MD&A.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Business Overview

Bengal's producing and non-producing assets are situated in Australia's Cooper Basin, a region featuring large accumulations of very light and high-quality crude oil and natural gas. The Company's core Australian assets, Petroleum Lease ("PL") 303 Cuisinier, Authority to Prospect ("ATP") 934 Barrolka, Potential Commercial Area ("PCA") 332 (formerly ATP 732) Tookoonooka, and four petroleum licenses are situated within an area of the Cooper Basin that is well served with production infrastructure and take-away capacity for produced crude oil and natural gas. Still in early stages in terms of appraisal and development, Bengal believes these assets offer attractive upside potential for both oil and gas. Australia presents a stable political, fiscal, and economic environment in which to operate, and a favourable royalty regime for oil and gas production. In addition, Bengal owns a 26km 6" high pressure gas pipeline (PPL 138) connecting the Wareena field to a large raw gas network passing Bengal's prospects at ATP 934.

Under the State of Queensland Regulatory process, ATPs are granted by the State generally for a period of twelve years with one-third of the original grant area expiring every four years. At the end of the final term of the ATP, an application can be made to continue a portion of the permit in the form of a Potential Commercial Area ("PCA"). PCAs have a life span of five to fifteen years. PCA applications include a commercial viability report that indicates that the area is likely to be commercially viable within the applied term. This allows for extra time to commercialize any identified Resource. These PCAs remain a part of the ATP until expiry. If a discovery of oil or gas is made, an application for a PL is made to allow for production. PLs are granted for up to a thirty-year term.

Bengal has a 30.375% interest in two PLs on the former ATP 752 Barta block, PL 303 and PL 1028. In addition, the Company has three PCAs associated with ATP 752 which are the Barta block, PCA 206 and PCA 207 and PCA 155 in the Wompi block which contains the Nubba well. Bengal also holds a 100% working interest in four PLs including PPL 138 adjacent to the 100% owned ATP 934.

Following extensive public consultation, in late December 2023 the Queensland government released a document outlining its plans for increased restrictions to petroleum activities within the rivers and floodplains area of the Lake Eyre Basin (LEB) catchment. Bengal Energy areas affected by this are the western portion of the Durham Downs block (ATP 934) where Bengal holds a 40% interest and PCA 115 (Nubba)(ATP 752 Wompi) in which Bengal holds a 38% interest. Of these permits, work can continue to develop gas resources under an existing petroleum lease. No additional PL's have been acquired by Bengal since the new Queensland Legislation came into effect.

In the Wompi portion of the Bengal ATP 752 permit (Bengal 38.5% WI) the discovered volumes of natural gas in the Nubba well are deemed too small for commerciality, and Bengal and partners will move to relinquish this block. In the western portion of ATP 934 in the Durham Downs East block (Bengal 40% W.I.) which is the part of ATP 934 which was farmed out, the operator is expected to withdraw from the permit subject to the terms of the Joint Operating Agreement (JOA) leaving Bengal with 100% interest. Bengal anticipates relinquishing this interest and is working with the regulator to secure favourable relinquishment terms. Neither of these assets have any carrying value in the Company's financial statements. Bengal prospects within Barrolka East (ATP 934 – 100% WI), Ghina (PL 1109 – 100% WI), Wareena (PL 1110 - 100% WI), Ramses PL 411, Karnak PL 188 and Tookoonooka (PCA 332 – 100% WI) are unaffected.

<u>AUSTRALIA – Cooper Basin, Queensland</u>

PL 303 Barta Block Cuisinier (controlling permit ATP 752) (30.357% WI)

The Company continues to evaluate the results of its water injection program at Cuisinier. The injection of produced formation water has resulted in both increased production in up to four offsetting wells and reduced water handling charges. Whilst the JV has observed compelling evidence that the overall field decline has been temporarily arrested with a modest upward trend in oil production during periods of operation, the water injection program has suffered from extended shut-in periods due to equipment failure and lack of available replacement parts. The program was intermittently operational during fiscal 2025; however, its impact to the joint venture is not currently measurable given unexplained changes to the Operator's allocation methodology. Bengal continues to challenge the Operator on this performance shortfall; however, despite reservoir response, it is expected that the operator will permanently suspend the pilot due to ongoing mechanical failures. Based on the results of the pilot, despite mechanical failures, the operator is evaluating locations to implement a waterflood in the main part of the reservoir.

PL 114 Wareena, PL 157 Ghina, PL 188 Ramses, PL 411 Karnak, PPL 138 pipeline (100% WI)

The Company has a 100% working interest in four PLs and a natural gas pipeline connected to transportation infrastructure into the Eastern Australia Gas Market. These non-productive PLs are highly compatible and near ATP 934. Bengal continues to integrate subsurface data from the PLs to enhance the Company's understanding of ATP 934 and to finalize the selection of exploration and appraisal drilling locations.

Included in this program are: two potential recompletions at Ramses; the Wareena 5 well; the Ghina recompilation; and the redrill or sidetracking opportunity at the Karnak well. The reinstatement of the existing gas pipeline will support the production of raw gas into existing infrastructure. The Company completed workover activities at Wareena 1 and Wareena 5 in November 2022. Initial test results indicate Wareena 1 would require additional stimulation and dewatering to yield commercial production rates. The Company was encouraged by wellhead pressure measured at Wareena 5 and believes that additional testing is justified upon availability of financing and field equipment.

The 100% ownership of these assets presents an appraisal and development opportunity that will be operated by the Company and is seen as a steppingstone for Bengal's natural gas platform upon which future development and appraisal work at the existing PLs and exploration growth through ATP 934 can be undertaken.

PCA 332 Tookoonooka (100% WI; formerly ATP 732)

Bengal conducted an acid treatment in 2022 on the Caracal-1 well to improve well bore inflow with positive results and moderate inflow of very light 53-degree gravity oil from the Wyandra zone. While not immediately commercially viable, these results are being evaluated with the possibility of fracture stimulation being considered to further enhance productivity being put in place. The well is currently suspended with shut-in pressure data being monitored.

ATP 732 reached the end of its term in March of 2023 and the Company lodged an application over the northern portion of the ATP for continuation in the form of PCA 332 for a further 15 years. Based on the positive results from Caracal-1, the application was approved on January 30, 2023. The PCA, granted by the Queensland Government in record time, provides much-needed certainty for Bengal to focus on its hydrocarbon projects in the Talgeberry-Tintaburra corridor. The majority of PCA 332 is covered by 3D seismic which has outlined the prospective targets as described in the Company's press release: "Bengal Energy Announces Independent Oil and Natural Gas Resource Report" dated March 30, 2022. The Company announced the completion of its Field Resource Maturation and Development Plan for its Tookoonooka PCA332 on March 14, 2024.

ATP 934 Barrolka East (100% WI)

ATP 934 is the Company's 100% owned natural gas exploration block. Bengal received approval of a special amendment for ATP 934 in March 2021 which relinquished 50% of the existing ATP area and extended the term of the ATP by entering an outcome based on the Later Work Permit ("LWP") for another 6 years to February 28, 2027. As part of the special amendment, another relinquishment of 118 sub blocks (50% of the remaining sub blocks) (88,972 acres) was required by February 28, 2023. The relinquishment was made and accepted by the regulator during April of 2023.The relinquished area was not considered to be prospective by the Company due to the lack of identified prospects and limited physical access. The current LWP includes the drilling of up to three wells and acquisition of 260 km^2 of 3D seismic. The Company has proposed a further swap of non-prospective land in the Durham Downs portion of this ATP in consideration for further extension.

AC/RL 10 Katandra (100% WI)

The Katandra permit is in the offshore Ashmore-Cartier region of the Timor Sea and holds the Katandra 1 oil discovery and the up-dip, Katandra North opportunity. The opportunity is hosted in the prolific Berriasian sandstones of the Upper Vulcan Formation. Bengal has entered into a binding term sheet agreement with an undisclosed party which grants an option to acquire an 80% working interest in the prospect in exchange for assignment of operatorship and carrying out all administrative support activities and possible future financing arrangements on the permit until such time as the applied for five year extension of the permit has been approved by the regulatory authority and the option has been exercised by the option holder. All associated expenses are being carried by the farm-in party.

Business development

Bengal is in ongoing discussions regarding potential farm-out opportunities surrounding its exploration and development portfolio as well as other corporate initiatives aimed at increasing shareholder value. The Company is unable to estimate the chance of success or update status until the culmination of any or all these initiatives.

OPERATING SUMMARY

($000s except per share, %, volumes and operating netback(1) amounts)	Three months ended December 31,		Nine months ended December 31,	
	2024	2023	**2024**	2023
Oil sales ($)	**1,431**	1,609	**4,585**	5,218
Operating netback(1) ($)	**706**	592	**2,218**	2,384
Cashflow from (used in) operating activities ($)	**298**	759	**(122)**	14
Funds from (used in) operations(1) ($)	**23**	(143)	**(68)**	(28)
-Per share ($) (basic and diluted)	**(0.00)**	(0.00)	**(0.00)**	(0.00)
Net loss	**(370)**	(504)	**(1,188)**	(1,081)
-Per share ($) (basic and diluted)	**(0.00)**	(0.00)	**(0.00)**	(0.00)
Capital expenditures ($)	**12**	71	**70**	399
Oil production (bbl/d)	**124**	174	**141**	175
Operating netback(1) ($/bbl)	**61.83**	36.97	**57.04**	49.41

(1) Non-IFRS and Other Financial Measures.

RESULTS OF OPERATIONS

Production	Three months ended December 31,		Nine months ended December 31,	
	2024	2023	**2024**	2023
Oil production (bbl)	**11,420**	16,013	**38,883**	48,246
Oil production (bbl/d)	**124**	174	**141**	175

The Company's share of total Cuisinier production in the current quarter was 11,420 bbls (124 bbl/d), a decrease of 29% compared to production of 16,013 bbls (174 bbl/d) in the third quarter of fiscal 2024.The Company continues to investigate the material change in production allocation provided by the Cuisinier operator which has resulted in a 50 bbl/d decrease in production net to Bengal during the second quarter when compared to the operator's budget. Bengal has requested field support to clarify the nature of the change in allocation and is awaiting further information from the operator.

Revenue/Pricing

The following table outlines the oil lifting from bills of lading, pipeline oil estimates, applicable prices and oil sales reflected in the Company's financial statements:

		Three months ended December 31,		Nine months ended December 31,	
		2024	2023	**2024**	2023
Oil lifting					
Volume (000s bbls)		**12.4**	16.0	**35.7**	51.0
Weighted average price (USD/bbl)		**76.92**	81.39	**83.73**	96.05
Sales CAD$	**A**	**1,485**	1,704	**4,244**	5,575
Pipeline oil					
Volume – change (000s bbls)		**(1.0)**	0.0	**0.0**	(2.8)
Price – change (USD/bbl)		**(6.38)**	(13.82)	**0.68**	(5.41)
Net sales – change CAD$	**B**	**(54)**	(95)	**341**	(357)
Total oil sales CAD$	**A+B**	**1,431**	1,609	**4,585**	5,218

The price received for Bengal's Australian oil sales is benchmarked on US Brent for the month in which the bill of lading occurs, plus a realized premium due to oil quality differences. Pipeline oil is the term used to describe oil moving along the pipeline from the wellhead to the port which has been legally transferred to the buyer but not priced and waiting to be sold. Lifting occurs when the oil is moved from the port to the ship. The Cuisinier Joint Venture has recently negotiated a revised COPSA with corresponding transportation agreements effective January 1, 2025, through to December 31, 2025.

The realized weighted average price of oil lifting sales decreased by 5% from US$81.39/bbl for the three months ended December 31, 2023, to US$76.92/bbl for the three months ended December 31, 2024. For the nine months ended December 31, 2024, the realized weighted average price of oil lifting sales increased by 3% to

USD$83.73/bbl, helped by timing of oil lifting in the months with higher reference pricing. For the three months ended December 31, 2024, over 50% of oil lifting was in the month of October 2024, with US$79.53/bbl.

Oil sales were $1.4 million in the quarter ended December 31, 2024. Oil sales were 11% lower compared with the $1.6 million recorded in the quarter ended December 31, 2023, stemming from lower sales volume, offset by higher realized price between the two period, as well as by the higher pipeline volume at period end December 31, 2024, at Brent reference price of US$82.86/bbl.

Oil sales were $4.6 million for the nine months ended December 31, 2024; a 12% decrease compared to $5.2 million in the nine months ended December 31, 2023. This correlates with the 19% decrease in production between the two fiscal period, offset by higher realized oil prices of $117.92/bbl in the current fiscal period compared to $108.15/bbl for the nine months ended December 31, 2023, which was supported by increase in the value of US dollars compared to Canadian and Australian dollars.

The following table outlines average benchmark prices:

	Three months ended December 31,		**Nine months ended December 31,**	
	2024	2023	**2024**	2023
Brent oil ($/bbl)	**104.41**	113.93	**109.76**	111.79
Brent oil (USD/bbl)	**74.61**	83.73	**79.70**	82.90
Number of CAD$ for 1 USD	**1.40**	1.36	**1.38**	1.35
Number of CAD$ for 1 AUD	**0.91**	0.89	**0.91**	0.89

The following table outlines operating netback:

Operating netback[1]	**Three months ended December 31,**		**Nine months ended December 31,**	
($000s and $/bbl)	**2024**	2023	**2024**	2023
Oil sales	**1,431**	1,609	**4,585**	5,218
Royalties	**(86)**	(205)	**(349)**	(419)
Operating expense	**(639)**	(812)	**(2,018)**	(2,415)
Operating netback	**706**	592	**2,218**	2,384
Oil sales ($/bbl)	**125.31**	100.48	**117.92**	108.15
Royalties ($/bbl)	**(7.53)**	(12.80)	**(8.98)**	(8.68)
Operating expense ($/bbl)	**(55.95)**	(50.71)	**(51.90)**	(50.06)
Operating netback ($/bbl)	**61.83**	36.97	**57.04**	49.41

[1] See Non-IFRS and Other Financial Measures.

Operating netback was $61.83/bbl for Q3 fiscal 2025, 67% higher than Q3 fiscal 2024 of $36.97/bbl. The increase in operating netback was driven primarily by higher oil sales price of $125.31/bbl compared to $100.48/bbl, (25%) as well as the 41% lower royalties per barrel.

Operating netback for the nine months ended December 31, 2024, of $57.04/bbl compared to the nine months ended December 31, 2023 of $49.41/bbl, increased by 15%, with the oil sales realized price contributing to majority of the increase.

Royalties

Royalties	**Three months ended December 31,**		**Nine months ended December 31,**	
	2024	2023	**2024**	2023
Royalty expense	**86**	205	**349**	419
$/bbl	**$ 10.28**	$ 12.80	**$ 9.58**	$ 8.68
% of revenue	**6.0%**	12.7%	**7.6%**	8.0%

In Queensland Australia, oil royalties are based on a government-established rate net of eligible expenditures which scales according to benchmark oil prices plus a Native Title royalty of 1%. Royalties were lower at 6.0% in the three months ended December 31, 2024, compared to 12.7% in the three months ended December 31, 2023. The higher royalty percentage in the three months ended December 31, 2023, contained year-end royalty adjustments booked by the operator, which added additional royalties in fiscal 2024 and reduced year to date royalties in fiscal 2025.

Royalties were lower by $0.1 million between the nine months ended December 31, 2024, compared to the nine months ended December 31, 2023, with the same factors as above. On an annual basis, royalty rate is expected to be 7% to 9% for the remainder of fiscal 2025.

Operating Expense

Operating Expense		**Three months ended December 31,**			**Nine months ended December 31,**	
($000s and $/bbl)		**2024**	2023		**2024**	2023
Production		**212**	304		**652**	800
Transportation		**427**	508		**1,366**	1,615
		639	812		**2,018**	2,415
Production ($/bbl)		**18.56**	18.98	**$**	**16.77**	$ 16.58
Transportation ($/bbl)		**37.39**	31.72	**$**	**35.13**	$ 33.47
	$	**55.95**	$ 50.71	**$**	**51.90**	$ 50.06

Total operating expense during Q3 fiscal 2025 decreased by 21% compared to Q3 fiscal 2024 primarily due to decrease in production as previously described.

The operating expense for the nine months ended December 31, 2024, was $2.0 million, 16% lower than the nine months ended December 31, 2023, of $2.4 million. Operating expense per barrel in these two fiscal periods was 4% higher from $50.06 to $51.90, stemming from the 19% lower volumes, offset by the fixed component of operating costs.

General and Administrative (G&A) Expense

G&A	**Three months ended December 31,**		**Nine months ended December 31,**	
	2024	2023	**2024**	2023
Net G&A expense	**644**	713	**2,163**	2,355
Capitalized G&A	**-**	28	**19**	138
Total G&A expense	**644**	741	**2,182**	2,493

Net G&A expense for the three months ended December 31, 2024, was $0.6 million, comparable to $0.7 million in the three months ended December 31, 2023.

For the nine months ended December 31, 2024, bet G&A expense was $2.2 million, 12% lower than $2.4 million for the nine months ended December 31, 2023. This was to lower activity levels and reduced staffing levels.

Share-based Compensation ("SBC")

SBC	**Three months ended December 31,**		**Nine months ended December 31,**	
	2024	2023	**2024**	2023
Expensed SBC	**7**	7	**9**	23
Capitalized SBC	**-**	-	**4**	1
	7	7	**13**	24

The Company uses the Black-Scholes pricing model to estimate the fair value of options on the date of grant and amortizes the estimated expense over the vesting period with a corresponding charge to contributed surplus. Options expire five years from the grant date. There were 750,000 options issued during the third quarter of fiscal 2025 with a value of $0.01 per share and a total of 1,500,000 options issued during the nine months ended December 31, 2024. Share-based compensation for Q3 fiscal 2025 includes only the value of newly granted options in fiscal 2025 as the value of previous grants has been fully recognized in previous periods.

The Company uses the Black-Scholes pricing model to estimate the fair value of options on the date of grant and amortizes the estimated expense over the vesting period with a corresponding charge to contributed surplus. Options expire five years from the grant date.

Depletion and Depreciation (DD&A)

DD&A	Three months ended December 31,		Nine months ended December 31,	
	2024	2023	**2024**	2023
Petroleum and natural gas properties	**274**	299	**932**	868
Other assets	**1**	1	**2**	2
Right-of-use assets	**-**	7	**-**	22
DD&A	**275**	307	**934**	892
DD&A ($/bbl)	**24.08**	19.17	**24.02**	18.49

Depletion expense increased on a per barrel basis in the current fiscal quarter of 2025 compared to the third fiscal quarter of 2024 due to decrease in reserves volumes on which depletion is calculated.

Finance Expense

Finance Expense	Three months ended December 31,		Nine months ended December 31,	
	2024	2023	**2024**	2023
Accretion expense on decommissioning and restoration liability	**38**	45	**113**	133
Interest expense (income)	**87**	(1)	**93**	7
	125	44	**206**	140

Accretion expense on decommissioning and restoration liabilities was consistent between the three and nine months ended December 31, 2024, and December 31, 2023. Interest expense for three months ended December 31, 2024, stems from the Joint Venture payment plan with a carrying value of $2.2 million entered into in October 2024.

CAPITAL EXPENDITURES

Capital expenditures	Three months ended December 31,		Nine months ended December 31,	
	2024	2023	**2024**	2023
Geological, geophysical and workovers	**12**	71	**84**	399
Drilling	**-**	-	**-**	-
	12	-	**84**	399
Exploration and evaluation expenditures	**-**	10	**15**	52
Development and production expenditures	**12**	61	**69**	347
	12	71	**84**	399

Development and production expenditures were minimal in the three and nine months ended December 31, 2024, as the Company is looking to obtain additional financing and joint venture partners for capital development.

SHARE CAPITAL

Trading history	Three months ended December 31,		Nine months ended December 31,	
	2024	2023	**2024**	2023
High ($/share)	**0.01**	0.05	**0.04**	0.08
Low ($/share)	**0.01**	0.02	**0.04**	0.02
Close ($/share)	**0.01**	0.03	**0.01**	0.03
Average Daily Volume	**1,733**	1,267	**9,957**	3,338
Weighted average shares outstanding (000s)				
Basic	**485,304**	485,304	**485,304**	485,304
Diluted	**485,304**	485,304	**485,304**	485,304

At February 6, 2025, there were 485,304,215 common shares issued and outstanding, together with 9,570,000 outstanding options.

LIQUIDITY RISK AND CAPITAL RESOURCES

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including work commitments, as they are due. Bengal prepares an annual budget and updates forecasts for operating, financing, and investing activities on an ongoing basis to ensure it will have sufficient liquidity to meet its liabilities when due.

Bengal's financial liabilities consist of trade and other payables and Joint Venture payment plan, totalling $3.1 million at December 31, 2024 (March 31, 2024 - $3.2 million).

At December 31, 2024, the Company had working capital of $1.0 million (March 31, 2024 – $0.2 million), which the Company defines as total current assets less total current liabilities.

The Company's working capital includes both accrued accounts receivable and trade and other payable, and the current portion of Joint Venture payment plan. The Company does not have the legal right to offset these accounts and therefore there is a risk that the inability to collect on accrued receivables could impair Benga's ability to pay joint venture liabilities resulting in a default under the Cuisinier Joint Operating Agreement. This default could result in the Company losing some or all of its working interest in the Cuisinier field.

Over the past 21 months, the Company has accrued an outstanding balance of $2.0 million due to the operator of the Cuisinier field resulting from withholding payments associated with disputed overhead charges. These disputed charges relate to overhead allocations, interest and penalties that Bengal does not consider allowable by the operator and is challenging through the joint venture audit process. During October 2024, the Company entered into an agreement with the operator to settle the outstanding payable under a 24-month payment plan that will include equal principal installments plus interest (Westpac Bank Bill Swap Rate or "BBSW") through October 2026. Any audit adjustments posted during this time will reduce the outstanding payable amount and any failure to meet the payment obligations of the plan will result in a default under the terms of the joint venture agreement resulting in the loss of some or all the Company's working interest in the Cuisinier field.

The Company also has significant capital work commitments associated with its exploration and evaluation assets that if unfulfilled could result in a loss of acreage as described in Note 17 of the accompanying interim condensed consolidated financial statements and without future development could result in a decline in production and revenues with additional net cash used in operating activities. The Company's ability to continue as a going concern is dependent upon its ability to generate net cash from operating activities and/or raise additional financing to meet its ongoing operational requirements and to fund its future development costs associated with exploration and evaluation assets and petroleum and natural gas properties development. As outlined in Note 2 of the interim condensed consolidated financial statements, the Company has assessed that there is material uncertainty that may cast significant doubt about its ability to continue as a going concern.

The majority of the Company's oil sales are benchmarked on US Brent prices. The Company incurs most of its expenditures in Australian dollars whereas the Company generates most of its revenues in US dollars. The Company is acting with its joint venture partners to reduce discretionary operational spending and limiting its capital expenditures capital towards lower risk projects that meet its internal economic hurdles and are expected to offer near-term cash flow upside.

OFF BALANCE SHEET TRANSACTIONS

The Company does not have any off-balance sheet transactions as at December 31, 2024.

COMMITMENTS

The Queensland Government regulatory authority granted the Company Authority to Prospect 934 ("ATP 934") under a revised work program on March 1, 2015. The Company consolidated its ownership of ATP 934, resulting in a 100% and 40% operating interest in the northern and southern block of this permit respectively in 2018. The work program consists of 260 km^2 of 3D seismic and up to three wells. In February 2023, the Company extended its ATP 732 permit and received a Potential Commercial Area ("PCA") over 343 km^2. This included additional work commitments related to both ATP 732 and PCA 332 as outlined below.

At December 31, 2024, the Company had the following capital work commitments:

Permit	Work Program	Obligation period ending	Estimated expenditure (net) (millions CAD$)[(1)]
ATP 934 – Onshore Australia	260 km^2 3D seismic and up to three wells	February 2027	7.9
ATP 732 – Onshore Australia	Geological and up to three wells	February 2029	6.8
PCA 332 – Onshore Australia	Initial Production testing	February 2029	3.9
PCA 332 – Onshore Australia	Extended Production testing	February 2035	2.3

(1) Translated at December 31, 2024 at an exchange rate of AUD$1.00 = CAD$0.8915.

The Company entered into a lease agreement for office space in October 2023 with a contract term ending in February 2027.

At December 31, 2024, the contractual obligations for which the Company is responsible are as follows:

Contractual obligations (000s)	**Total**	Less than 1 year	1-3 years	4-5 years	After 5 years
Office lease	**50**	23	27	-	-
Joint Venture payment plan	**1,673**	969	704	-	-
Decommissioning and restoration	**3,695**	-	794	-	2,901
	5,368	969	1,498	-	2,901

SELECTED QUARTERLY INFORMATION

Fiscal quarter ($000s except per share, volumes and operating netback[(1)])	**Dec 31 2024 Q3 2025**	Sep 30 2024 Q2 2025	Jun 30 2024 Q1 2025	Mar 31 2024 Q4 2024	Dec 31 2023 Q3 2024	Sep 30 2023 Q2 2024	Jun 30 2023 Q1 2024	Mar 31 2023 Q4 2023
Oil sales ($)	**1,431**	1,252	1,902	1,815	1,609	1,937	1,672	1,954
Cashflow from (used in) operating activities ($)	**298**	(129)	(291)	(287)	592	(643)	(102)	(704)
Funds from (used in) operations[(1)] ($)	**23**	(294)	203	329	(143)	123	(8)	(431)
-Per share($)-basic and diluted	**-**	-	-	-	-	-	-	-
Net (loss) income	**(370)**	(608)	(210)	(11,647)	(504)	(213)	(364)	(803)
-Per share($)-basic and diluted	**-**	-	-	-	-	-	-	-
Capital expenditures ($)	**12**	9	63	75	71	115	213	395
Working capital (deficit)	**957**	152	448	199	(53)	160	(491)	(284)
Total assets	**33,558**	35,494	35,326	34,361	47,987	46,793	48,419	49,697
Shares outstanding (000)	**485,304**	485,304	485,304	485,304	485,304	485,304	485,304	485,304
Operations:								
Oil production (bbl/d)	**124**	127	174	162	174	176	176	182
Operating netback[(1)] ($/bbl)	**61.83**	42.84	64.08	67.49	36.97	59.48	51.68	65.75

(1) See Non-IFRS and Other Financial Measures on page 12 of this MD&A.

Production was relatively stable over the past eight quarters averaging 169 bbl/d despite natural reservoir declines in the Cuisinier oil field until the current quarter when field allocations resulted in a 50 bbl/d decrease in production net to Bengal. Ongoing volatility in US Brent prices from Q3 fiscal 2023 to Q2 fiscal 2025 resulted in volatility in oil sales with the production declines impacting the current quarter as described above. Net income, cashflow and funds from operations were impacted primarily by production volumes. The impact of volatile commodity pricing and production decreases in the quarter impacted cash flow from operations. Working capital deficiency occurred during the fiscal Q4 2023 and fiscal Q1 2024 as a result of the Cuisinier joint venture royalty adjustment. Working capital at Q3 2025 improved due to Joint Venture payment plan obtained in October 2024. Net loss in Q4 2024 was impacted by an impairment expense of $11.6 million recognized in its property plant and equipment balance.

DISCLOSURE CONTROLS & PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING (ICFR)

Disclosure Controls and Procedures

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and includes controls and procedures designed to ensure that information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the Company's management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure.

The Chief Executive Officer and Chief Financial Officer oversee this evaluation process and have concluded that the design and operation of these disclosure controls and procedures are not effective due to the material weaknesses identified in internal controls over financial reporting as noted below. The Chief Executive Officer and Chief Financial Officer have individually signed certifications to this effect.

Internal Controls over Financial Reporting

The Chief Executive Officer and Chief Financial Officer of Bengal are responsible for designing and ensuring the operating effectiveness of internal controls over financial reporting ("ICFR") or causing them to be designed and operating effectively under their supervision in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. Bengal's certifying officers have assessed the design and operating effectiveness of internal controls over financial reporting and concluded that the Company's ICFR were effective at December 31, 2024, with the exception of the material weaknesses noted below.

No changes in internal controls over financial reporting were identified during the period that have materially affected or are reasonably likely to materially affect the Company's internal controls over financial reporting.

While Bengal's Chief Executive Officer and Chief Financial Officer believe the Company's internal controls and procedures provide a reasonable level of assurance that they are reliable, an internal control system cannot prevent all errors and fraud. It is management's belief that any control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

During the design and operating effectiveness assessment, certain material weaknesses in internal controls over financial reporting were identified, as follows:

- Management is aware that there is a lack of segregation of duties due to the small number of employees dealing with general and administrative and financial matters. However, management believes that at this time the potential benefits of adding employees to clearly segregate duties do not justify the costs; and
- Bengal does not have full-time in-house personnel to address all complex and non-routine financial accounting issues and tax matters that may arise. It is not deemed as economically feasible at this time to have such personnel. Bengal relies on external experts for review and advice on complex financial accounting issues.

These material weaknesses in internal controls over financial reporting result in a reasonable possibility that a material misstatement will not be prevented or detected on a timely basis. Management and the Board of Directors work to mitigate the risk of material misstatement; however, management and the Board of Directors do not have reasonable assurance that this risk can be reduced to a remote likelihood of a material misstatement.

APPLICATION OF CRITICAL ACCOUNTING ESTIMATES

The timely preparation of the financial statements requires management to make judgements, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, actual results may differ from these estimates, which are reviewed on an ongoing basis.

Significant estimates and judgments made by management in the preparation of these financial statements are outlined below. The economic climate may have significant adverse impacts on the Company, including material declines in revenue and cash flows, and related impacts to working capital levels and/or debt balances, which may also have a direct impact on the Company's operating results and financial position. These and other factors may adversely affect the Company's liquidity and the Company's ability to generate income and cash flows to meet the Company's current and future obligations. A full discussion of the Company's critical judgments and accounting estimates is included in its fiscal 2024 consolidated financial statements dated June 13, 2024.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The accounting policies applied are consistent with those of the previous fiscal year as described in Note 3 of the Company's consolidated financial statements for the year ended March 31, 2024.

NON-IFRS AND OTHER FINANCIAL MEASURES

Non-IFRS Financial Measures

Within this MD&A, references are made to terms commonly used in the oil and gas industry. Operating netback, operating netback per barrel, funds from (used in) operations, funds from (used in) operations per share, do not have any standardized meaning under IFRS and are referred to as non-IFRS measures. Management believes the presentation of the non-IFRS measures above provide useful information to investors and shareholders as the measures provide increased transparency and the ability to better analyze performance against prior periods on a comparable basis.

Operating Netback

Bengal utilizes operating netback as key performance indicator and is utilized by Bengal to better analyze the operating performance of its petroleum and natural gas assets against prior periods. Operating netback is calculated oil sales deducting royalties and operating expenses. The following table reconciles petroleum and natural gas revenue to operating netback:

Operating netback	**Three months ended December 31,**		**Nine months ended December 31,**	
($000s)	**2024**	2023	**2024**	2023
Oil sales	**1,431**	1,609	**4,585**	5,218
Royalties	**(86)**	(205)	**(349)**	(419)
Operating expense	**(639)**	(812)	**(2,018)**	(2,415)
Operating netback	**706**	592	**2,218**	2,384

Funds from (used in) operations

Management utilized funds from (used in) operations as a measure to assess the Company's ability to generate cash not subject to short-term movements in non-cash operating working capital. Funds from (used in) operations is calculated by adding back all non-cash expense deductions to the net loss for the period ended. The following table reconciles cash from operating activities to funds from operations, which is used in this MD&A:

Funds from (used in) operations	**Three months ended December 31,**		**Nine months ended December 31,**	
($000s)	**2024**	2023	**2024**	2023
Cash flow from (used in) operating activities	**298**	759	**(122)**	14
Add back (deduct):				
Changes in non-cash working capital	**(275)**	(902)	**54**	(42)
Funds from (used in) operations	**23**	(143)	**(68)**	(28)

CAPITAL MANAGEMENT MEASURES

Working capital

Bengal uses working capital to monitor its capital structure, liquidity and its ability to fund current operations. Working capital is calculated as current assets less current liabilities but excludes other obligations and current portion of decommissioning obligations.

NON-IFRS FINANCIAL RATIOS

Bengal uses operating netback per boe to assess the Company's operating performance on a per unit of production basis. Operating netback per barrel equals operating netback divided by the applicable number of barrels of production.

Operating netback	Three months ended December 31,		Nine months ended December 31,	
($/bbl)	**2024**	2023	**2024**	2023
Oil sales	**125.31**	100.48	**117.92**	108.15
Royalties	**(7.53)**	(12.80)	**(8.98)**	(8.68)
Operating expense	**(55.95)**	(50.71)	**(51.90)**	(50.06)
Operating netback	**61.83**	36.97	**57.04**	49.41

Bengal uses funds from operations per share to assess the ability of the Company to generate the funds necessary for financing, operating, and capital activities on a per-share basis. This is a non-IFRS measure calculated by dividing funds from operations by weighted average basic and diluted shares outstanding for the periods disclosed.

ABBREVIATIONS

The following abbreviations used in this MD&A have the meanings set forth below:

bbl	-	barrel
bbl/d	-	barrels per day
$/bbl	-	dollars per barrel
ft^3	-	cubic feet
boe/d		barrels of oil equivalent per day
FY	-	fiscal year
K	-	thousand
km	-	kilometres
km^2	-	square kilometres
Q1	-	three months ended June 30
Q2	-	three months ended September 30
Q3	-	three months ended December 31
Q4	-	three months ended March 31
WI	-	working interest
COSPA	-	crude oil sales and purchase agreement
BBSW	-	bank bill swap rate

RISK FACTORS

There are a number of risk factors facing companies that participate in the oil and gas industry. A complete list of risk factors is provided in Bengal's Annual Information Form dated July 2, 2024, filed on SEDAR at www.sedarplus.ca.

Companies engaged in the oil and gas industry are exposed to a number of business risks, which can be described as operational, financial and political risks, many of which are outside of the Company's control. More specifically, these include risks of economically finding Reserves and producing oil and gas in commercial quantities, marketing the production, commodity prices, environmental and safety risks, and risks associated with the foreign jurisdiction in which the Company operates. In order to mitigate these risks, the Company has an experienced base of qualified technical and financial personnel in Canada. Further, the Company has focused its foreign operations and plans to target future foreign operations in known and prospective hydrocarbon basins in jurisdictions that have previously established long-term oil and gas ventures with foreign oil and gas companies.

Bengal monitors and updates its cash projection models on a regular basis, which assists in the timing decision of capital expenditures. Farm-outs of projects may be arranged if capital constraints are an issue or if the risk profile dictates that Bengal wishes to hold a lesser working interest position. Equity, if available and if on favorable terms, may be utilized to help fund Bengal's capital program.

An investment in the shares of the Company should be considered speculative due to the nature of the Company's involvement in the exploration for and the acquisition, development and production of oil and natural gas in foreign countries, and its current stage of development. An investor should consider carefully the risk factors set out in the annual information form and consider all other information contained herein and, in the Company's, other public filings before making an investment decision. Additional risks and uncertainties not currently known to the management of the Company may also have an adverse effect on Bengal's business and the information set out in the annual information form does not purport to be an exhaustive summary of the risks affecting Bengal.

Exploration, Development and Production Risks

Oil and natural gas exploration involves a high degree of risk, for which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that expenditures made on future exploration by Bengal will result in new discoveries of oil or natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over pressured zones, tools lost in the hole and changes in drilling plans and locations because of prior exploratory wells or additional seismic data and interpretations thereof.

The long-term commercial success of Bengal will depend on its ability to find, acquire, develop and commercially produce oil and natural gas Reserves. No assurance can be given that Bengal will be able to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, Bengal may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic.

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

In addition, oil and gas operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, cratering, sour gas releases, fires, and spills. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on future results of operations, liquidity, and financial condition.

Bengal attempts to minimize exploration, development, and production risks by utilizing a high-end technical team with extensive experience and multidisciplinary skill sets to assure the highest probability of success in its drilling efforts. Bengal’s collaboration of a team of seasoned veterans in the oil and gas business, each with a unique expertise in the various upstream to downstream technical disciplines of prospect generation to operations, provides the best assurance of competency, risk management and drilling success. A full cycle economic model is utilized to evaluate all hydrocarbon prospects. Detailed geological and geophysical techniques are regularly employed including 3D seismic, petrography, sedimentology, petrophysical log analysis and regional geological evaluation.

Risks Associated with Foreign Operations

International operations are subject to political, economic and other uncertainties, including, among others, risk of war, risk of terrorist activities, border disputes, expropriation, renegotiations or modification of existing contracts, restrictions on repatriation of funds, import, export and transportation regulations and tariffs, taxation policies, including royalty and tax increases and retroactive tax claims, exchange controls, limits on allowable levels of production, currency fluctuations, labor disputes, sudden changes in laws, government control over domestic oil and gas pricing and other uncertainties arising out of foreign government sovereignty over the Company's international operations. With respect to taxation matters, the governments, and other regulatory agencies in the foreign jurisdictions in which Bengal operates and intends to operate in the future may make sudden changes in laws relating to taxation or impose higher tax rates, which may affect Bengal’s operations in a significant manner. These governments and agencies may not allow certain deductions in calculating tax payable that Bengal believes should be deductible under applicable laws or may have differing views as to values of transferred properties. This can result in significantly higher tax payable than initially anticipated by Bengal. In many circumstances, readjustments to tax payable imposed by these governments and agencies may occur years after the initial tax amounts were paid by Bengal, which can result in the Company having to pay significant penalties and fines. Furthermore, in the event of a dispute arising from international operations, the Company may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of courts in Canada.

Prices, Markets and Marketing of Crude Oil and Natural Gas
Oil and natural gas are commodities that have prices determined based on world demand, supply and other factors, all of which are beyond the control of Bengal. World prices for oil and natural gas have fluctuated in recent years due to geo-political matters. Any material decline in prices could result in a reduction of net production revenue. Certain wells or other projects may become uneconomic because of a decline in world oil prices and natural gas prices, leading to a reduction in the volume of Bengal’s oil and gas Reserves. Bengal might also elect not to produce from certain wells at lower prices. All these factors could result in a material decrease in Bengal’s future net production revenue, causing a reduction in its oil and gas acquisition and development activities. In addition to establishing markets for its oil and natural gas, Bengal must also successfully market its oil and natural gas to prospective buyers. The marketability and price of oil and natural gas, which may be acquired or discovered by Bengal, may be affected by numerous factors beyond its control.

The ability of Bengal to market its natural gas may depend upon its ability to acquire space on pipelines, which deliver natural gas to commercial markets. Bengal may also likely be affected by deliverability uncertainties related to the proximity of its Reserves to pipelines and processing facilities and related to operational problems with such pipelines and facilities and extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

Substantial Capital Requirements and Liquidity
Bengal’s cash flow from its Reserves may not be sufficient to always fund its ongoing activities, as was the case in the current fiscal quarter. From time to time, Bengal may require additional financing to carry out its oil and gas acquisition, exploration, and development activities. Failure to obtain such financing on a timely basis could cause Bengal to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If Bengal’s revenues from its Reserves decrease because of lower oil and natural gas prices or otherwise, it may affect Bengal’s ability to expend the necessary capital to replace its Reserves or to maintain its production. If Bengal’s funds from (used in) operations are not sufficient to satisfy its capital expenditure requirements or interest requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available on terms acceptable to Bengal.

Bengal monitors and updates its cash projection models on a regular basis, which assists in the timing decision of capital expenditures. Farm outs of projects may be arranged if capital constraints are an issue or if the risk profile dictates that Bengal wishes to hold a lesser working interest position. Equity, if available and if on favorable terms, may be utilized to help fund Bengal’s capital program.

Health, Safety and Environment
All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, state, and local laws 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. The legislation also requires that wells and facility sites be operated, maintained, abandoned, and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Company to incur costs to remedy such discharge.

Changing Regulation
Emission, carbon and other regulations impacting climate and climate related matter are dynamic and constantly evolving. With respect to environmental, social and governance (“ESG”) and climate reporting, the International Sustainability Standards Board has issued an IFRS Sustainability Disclosure Standard with the aim to develop sustainability disclosure standards that are globally consistent, comparable, and reliable. In addition, the Canadian Securities Administrators have issued a proposed National Instrument 51-107 Disclosure of Climate related Matters. The cost to comply with these standards, and others that may be developed or evolve over time, has not yet been quantified by the Company.

Insurance
Bengal’s involvement in the exploration for and development of oil and gas properties may result in the Company becoming subject to liability for pollution, blow-outs, property damage, personal injury, or other hazards. Although Bengal has insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not, in all circumstances be insurable or, in certain circumstances, Bengal may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to Bengal. The occurrence of a significant event that Bengal is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Bengal’s financial position, results of operations or prospects.

Competition
Bengal actively competes for reserve acquisitions, exploration leases, licenses and concessions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial and personnel Resources than Bengal. Bengal's competitors include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators. Bengal’s ability to successfully bid on and acquire additional property rights, to discover Reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with its future industry partners and joint operators and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment.

Significant counterparty
Bengal’s operating activities are conducted primarily with a single counterparty responsible for the operations of the Cuisinier field as well as the transportation, marketing and sales of all the Company’s production and is responsible for the schedule of oil liftings and ultimate payment for oil sales. This counterparty invoices Bengal for all transportation costs and collects JV payments associated with development and operations as well as collects for and distributes proceeds of oil sales to Bengal. The material working capital assets and liabilities held by a single counterparty without a right to offset may create a liquidity risk.

ADDITIONAL INFORMATION

Additional information relating to Bengal is filed on SEDAR and can be viewed at www.sedarplus.ca. Information can also be obtained by contacting the Company at Bengal Energy Ltd., Suite 640, 630 – 6th Avenue SW., Calgary, Alberta T2P 0S8, by email to info@bengalenergy.ca or by accessing Bengal’s website at www.bengalenergy.ca.

FORWARD-LOOKING STATEMENTS

Certain statements contained within this MD&A constitute “forward-looking statements” or “forward-looking information” (“forward-looking statements”) as defined by applicable securities laws. These statements relate to future events or Bengal’s future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as “seek,” “anticipate,” “budget,” “plan,” “continue,” “estimate,” “expect,” “forecast,” “may,” “will,” “project,” “predict,” “potential,” “targeting,” “intend,” “could,” “might,” “should,” “believe” and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Bengal believes the expectations reflected in those forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this MD&A should not be unduly relied upon. The projections, estimates and beliefs contained in such forward-looking statements are based on management’s estimates, opinions, and assumptions at the time the statements were made, including assumptions relating to: the impact of economic conditions in North America and Australia and globally; industry conditions; changes in laws and regulations including, without limitation, the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; increased competition; the availability of qualified operating or management personnel; fluctuations in commodity prices, foreign exchange or interest rates; stock market volatility and fluctuations in market valuations of companies with respect to announced transactions and the final valuations thereof; results of exploration and testing activities; and the ability to obtain required approvals and extensions from regulatory authorities.

In particular, this MD&A contains forward-looking statements pertaining to the following:

- Oil and natural gas production levels;
- The size of the oil and natural gas Reserves;

- The adverse impacts on the Company as a result of the current challenging economic climate;
- Bengal's drilling program and waterflood program;
- The belief that the Cooper Basin assets offer attractive upside potential for oil and gas;
- Timing and re-assessment of restarting the planning and drilling selection for the 2024-2025 multi-well development and appraisal drilling campaign:
- The timing of the planned injection of produced formation water on the Barta Block PL 303 and the anticipated resulting production increases, future waterflood expansion phases, and reduced operating costs;
- The timing of the planned extended production test on the Nubba gas discovery well and plans to tie in the well;
- The planned 100% free carried well on the ATP 934 Barrolka and the expected assistance in de-risking the natural gas potential of the permit;
- The timing of equipping for production cased wells;
- The continued engagement in early-stage discussions with third parties with respect to potential business combination transactions;
- The continued integration of subsurface data from production licenses in the selection of exploration and appraisal drilling locations;
- Projections of market prices and costs including, but not limited to, expected royalty rates;
- Expectations regarding the ability to raise capital and to continually add to Reserves through acquisitions and development;
- That required payments will be met out of operational cash flows and alternative forms of financing;
- Bengal's ability to finance its potential working capital deficiency and to source funds for the same;
- Treatment under governmental regulatory regimes and tax laws;
- Capital expenditures program and estimates of costs; and
- That funding of working capital requirements, commitments and other planned expenses will be by cash on hand, cash flows, farm-outs, joint ventures, share issuances or other alternative forms of capital raising and funds will be sufficient to meet requirements including but not limited to Bengal's exploration activities through fiscal 2025 and its capital program.

The forward-looking statements contained herein are subject to numerous known and unknown risks and uncertainties that may cause Bengal's actual results, performance or achievement to differ materially from those expectations expressed in, or implied by, these forward-looking statements, including but not limited to, risks associated with:

- Fluctuations in commodity prices, foreign exchange or interest rates;
- Changes in the demand for or supply of Bengal's products;
- Liabilities inherent in oil and natural gas operations;
- The failure to obtain required regulatory approvals or extensions;
- The failure to satisfy the conditions under farm-in and joint venture agreements;
- The failure to secure required equipment and personnel;
- Changes in general global economic conditions including, without limitations, the economic conditions in North America and Australia;
- Uncertainties associated with estimating oil and natural gas Reserves;
- Increased competition for, among other things: capital, acquisitions of Reserves, undeveloped lands and skilled personnel;
- The availability of qualified operating or management personnel; and lack of in Country management associated with operating and exploration assets;
- Incorrect assessment of the value of acquisitions;
- Inability to meet commitments due to inability to raise funds or complete farm-outs;
- Geological, technical, drilling and processing problems;
- Bengal's development and exploration opportunities;
- The results of exploration and development drilling and related activities;
- Changes in laws and regulations including, without limitation, the adoption of new environmental, royalty and tax laws and regulations and changes in how they are interpreted and enforced;
- The ability to access sufficient capital from internal and external sources; and
- Counter-party credit risk, stock market volatility and market valuation of Bengal's stock.
- Weather

Statements relating to "Reserves" or "Resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, which the Resources and Reserves described, can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement. The forward-looking statements contained in this document speak only as of the date of this document and Bengal does not assume any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable securities laws. Additional information on these and other factors that could affect Bengal's operations and financial results are included in reports on file with Canadian securities authorities and may be accessed through the SEDAR website at www.sedarplus.ca. and at Bengal's website www.bengalenergy.ca.

Disclosure of Oil and Gas Information

Unless otherwise specified, Reserves data set forth in this document is based upon an independent reserve assessment and evaluation prepared by GLJ with an effective date of March 31, 2024 (the "GLJ Report"). The GLJ Report has been prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") and the reserve definitions contained in National Instrument 51-101 – Standards of Disclosure For Oil and Gas Activities.

This document discloses unbooked drilling locations. Unbooked locations are internal estimates based on the Company's prospective acreage and an assumption as to the number of wells that can be drilled per area based on industry practice and internal review. Unbooked locations do not have attributed Reserves or Resources. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas Reserves, Resources or production. The drilling locations on which the Company actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors.

Test Rates

References in this MD&A to production test rates are useful in confirming the presence of hydrocarbons; however, such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long-term performance or ultimate recovery. Readers are cautioned not to place reliance on such rates in calculating the aggregate production for the Company. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells**.** Accordingly, the Company cautions that the test results are historical and not indicative of expected production.

Internal Estimates

Certain information contained herein is based on estimated values the Company believes to be reasonable and are subject to the same limitations as discussed under "Forward-looking Statements" above.

CORPORATE INFORMATION

AUDITORS
MNP LLP • Calgary, Canada

LEGAL COUNSEL
Burnet, Duckworth & Palmer LLP • Calgary, Canada
Piper Alderman • Sydney, Australia

BANKERS
Royal Bank of Canada • Calgary, Canada
WestPac • Sydney, Australia

REGISTRAR AND TRANSFER AGENT
Computershare • Toronto, Canada

DIRECTORS
Chayan Chakrabarty
Dr. Brian J. Moss
Barry Herring
W. B. (Bill) Wheeler
R. Neal Grant

DISCLOSURE COMMITTEE
Chayan Chakrabarty
Jerrad Blanchard

AUDIT COMMITTEE
Barry Herring (Chairman)
W. B. (Bill) Wheeler
R. Neal Grant

RESERVES COMMITTEE
Dr. Brian J. Moss (Chairman)
Barry Herring
R. Neal Grant

COMPENSATION COMMITTEE
Dr. Brian J. Moss (Chairman)
Barry Herring
R. Neal Grant

GOVERNANCE AND NOMINATING COMMITTEE
W.B. (Bill) Wheeler (Chairman)
Dr. Brian J. Moss
Barry Herring

HEALTH, SAFETY AND ENVIRONMENT COMMITTEE
R. Neal Grant (Chairman)
W. B. (Bill) Wheeler
Dr. Brian J. Moss

OFFICERS
Chayan Chakrabarty, President & Chief Executive Officer
Richard N. Edgar, Executive Vice President
Jerrad Blanchard, Chief Financial Officer
Bruce Allford, Secretary

STOCK EXCHANGE LISTING – TSX: BNG

Interim Condensed Consolidated Financial Statements
(Unaudited)

Nine months ended December 31, 2024 and 2023

NOTICE

These interim condensed consolidated financial statements have not been reviewed by the Entity’s auditors.

(signed) “Chayan Chakrabarty”	(signed) “Jerrad Blanchard”
Chayan Chakrabarty	Jerrad Blanchard
President & Chief Executive Officer	Chief Financial Officer

BENGAL ENERGY LTD.

INTERIM CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(Thousands of Canadian dollars)
(unaudited)

As at	Note	December 31, 2024	March 31, 2024
Assets			
Current assets			
Cash and cash equivalents		**$ 702**	$ 692
Accounts receivable		**1,890**	1,782
Prepaids and deposits		**741**	903
		3,333	3,377
Exploration and evaluation assets	5	**12,142**	11,993
Property, plant and equipment	6	**18,083**	18,991
		$ 33,558	$ 34,361
Liabilities and Shareholders' Equity			
Current liabilities			
Trade and other payables		**$ 1,407**	$ 3,178
Joint Venture payment plan - current portion	7	**969**	-
		2,376	3,178
Joint Venture payment plan	7	**704**	-
Decommissioning and restoration liability	8	**3,627**	3,477
		6,707	6,655
Shareholders' Equity			
Share capital	9	**118,796**	118,796
Contributed surplus		**8,146**	8,136
Accumulated other comprehensive loss		**(3,064)**	(3,387)
Deficit		**(97,027)**	(95,839)
		26,851	27,706
		$ 33,558	$ 34,361

Going concern (Note 2)
Commitments (Note 17)

See accompanying notes to the interim condensed consolidated financial statements.

BENGAL ENERGY LTD.

INTERIM CONDENSED CONSOLIDATED STATEMENTS OF LOSS AND COMPREHENSIVE (LOSS) INCOME

(Thousands of Canadian dollars, except per share amounts)
(unaudited)

	Note		Three months ended December 31, 2024		2023		Nine months ended December 31, 2024		2023
Revenue									
Oil sales	11	**$**	**1,431**		1,609		**4,585**		5,218
Royalties			**(86)**		(205)		**(349)**		(419)
			1,345		1,404		**4,236**		4,799
Expenses									
General and administrative			**644**		713		**2,163**		2,355
Operating			**639**		812		**2,018**		2,415
Depletion and depreciation			**275**		307		**934**		892
Share-based compensation			**7**		7		**9**		23
(Gain) loss on foreign exchange			**(48)**		54		**21**		84
			(172)		(489)		**(909)**		(970)
Other expense									
Loss on disposition of equipment	6		**73**		(29)		**73**		(29)
Finance expense	13		**125**		44		**206**		140
Net loss			**(370)**		(504)		**(1,188)**		(1,081)
Exchange differences on translation of foreign operations			**(1,351)**		1,297		**326**		(233)
Net comprehensive (loss) income		**$**	**(1,721)**	$	793	**$**	**(865)**	$	(1,314)
Net loss per share - basic and diluted	12	**$**	**(0.00)**	$	(0.00)	**$**	**(0.00)**	$	(0.00)
Weighted average shares outstanding (000s)									
– basic	12		**485,304**		485,304		**485,304**		485,304
– diluted	12		**485,304**		485,304		**485,304**		485,304

See accompanying notes to the interim condensed consolidated financial statements.

BENGAL ENERGY LTD.

INTERIM CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(Thousands of Canadian dollars)
(unaudited)

For nine months ended	December 31, 2024	December 31, 2023
Share capital		
Balance at beginning of period	**$ 118,796**	$ 118,796
Balance at end of period	**118,796**	118,796
Contributed surplus		
Balance at beginning of period	**8,136**	8,103
Share-based compensation – expensed	**9**	23
Share-based compensation – capitalized	**1**	2
Balance at end of period	**8,146**	8,128
Accumulated other comprehensive loss		
Balance at beginning of period	**(3,387)**	(2,254)
Exchange differences translation of foreign operations	**323**	(233)
Balance at end of period	**(3,064)**	(2,487)
Deficit		
Balance at beginning of period	**(95,839)**	(83,111)
Net loss	**(1,188)**	(1,081)
Balance at end of period	**(97,027)**	(84,192)
Total Shareholders' Equity	**$ 26,851**	$ 40,245

See accompanying notes to the interim condensed consolidated financial statements.

BENGAL ENERGY LTD.

INTERIM CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Thousands of Canadian dollars)
(unaudited)

		Three months ended, December 31,		Nine months ended December 31,	
		2024	2023	**2024**	2023
Operating activities:					
Net loss		**(370)**	(504)	**(1,188)**	(1,081)
Add (deduct) non-cash items:					
Depletion and depreciation		**275**	307	**934**	892
Accretion on decommissioning liability		**39**	45	**113**	133
Share-based compensation		**7**	7	**9**	23
Loss on disposition of equipment		**73**	-	**73**	-
Unrealized foreign exchange (gain) loss		**(1)**	2	**(9)**	5
Funds from (used in) operations		**23**	(143)	**(68)**	(28)
Change in non-cash working capital	16	**275**	902	**(54)**	42
Net cash from (used in) operating activities		**298**	759	**(122)**	14
Investing activities:					
Exploration and evaluation expenditures	5	**-**	(10)	**(14)**	(51)
Property, plant and equipment expenditures	6	**(12)**	(60)	**(56)**	(346)
Proceeds on disposition of equipment	6	**110**	-	**193**	-
Research and development credits received		**-**	-	**-**	649
Change in non-cash working capital	16	**(1,903)**	(197)	**(1,703)**	(11)
Net cash (used in) from investing activities		**(1,805)**	(267)	**(1,580)**	241
Financing activities:					
Change in joint venture payment balance	7	**1,712**	**-**	**1,712**	**-**
Lease payments		**-**	(11)	**-**	(32)
Change in non-cash working capital	16	**-**	-	**-**	-
Net cash from (used in) financing activities		**1,712**	(11)	**1,712**	(32)
Net change in cash and cash equivalents		**205**	481	**10**	223
Cash and cash equivalents, beginning of period		**522**	511	**692**	795
Impact of foreign exchange		**(25)**	16	**-**	(10)
Cash and cash equivalents, end of period		**702**	1,008	**702**	1,008

See accompanying notes to the interim condensed consolidated financial statements.

1. REPORTING ENTITY

Bengal Energy Ltd. (the "Company" or "Bengal") is incorporated under the laws of the Province of Alberta and is involved in the exploration, development and production of oil and gas Reserves in Australia. The interim condensed consolidated financial statements (the "financial statements") of the Company as at December 31, 2024 and for the three and nine months ended December 31, 2024 and 2023 are comprised of the Company and its wholly owned subsidiaries including Bengal Energy Australia (Pty) Ltd. ("Bengal Pty") and Bengal Energy International Inc., which are incorporated in Australia and Canada respectively. The Company conducts many of its activities jointly with others; these financial statements reflect only the Company's proportionate interest in such activities.

The Company has its registered office at 2400, 525 – 8th Avenue SW, Calgary, Alberta T2P 1G1 and its head and principal office at Suite 640, 630 – 6th Avenue SW, Calgary, Alberta, Canada, T2P 0S8.

2. BASIS OF PREPARATION AND GOING CONCERN

These financial statements have been prepared in accordance with International Accounting Standard ("IAS") 34, "Interim Financial Reporting". These interim condensed consolidated financial statements do not include all of the information required for full annual financial statements and have not been reviewed by the Company's independent auditors.

These financial statements were approved and authorized for issuance by the Board of Directors on February 6, 2025.

The consolidated financial statements are prepared on a historical cost basis except as detailed in the accounting policies disclosed in the Company's audited consolidated financial statements for the year ended March 31, 2024. The Company's presentation currency is Canadian dollars. The functional currency of the Canadian parent entity is Canadian dollars; the functional currency of the Australian subsidiary is Australian dollars.

Going Concern

These financial statements have been prepared on a going concern basis. The going concern basis assumes that the Company will continue in operation for the foreseeable future and will be able to realize its assets and discharge its liabilities and commitments in the normal course of business.

At December 31, 2024, the Company had a positive working capital of $1.0 million (March 31, 2024 positive working capital of $0.2 million), which the Company defines as total current assets less total current liabilities, generated a net loss of $1.2 million (nine months ended December 31, 2023 – net loss of $1.1 million), and had net cash used in operating activities of $0.1 million (nine months ended December 31, 2023 – net cash generated by operating activities of $14,000).

The Company's working capital includes both accrued accounts receivable, accounts payable, and Joint Venture payment plan balances due to the Operator of the Cuisinier field. The Company does not have the legal right to offset these accounts and therefore there is a risk that the inability to collect on accrued receivables could impair Bengal's ability to pay joint venture liabilities resulting in a default under the Cuisinier Joint Operating Agreement. This default could result in the Company losing some or all of its working interest in the Cuisinier field. The Company also has significant capital work commitments associated with its exploration and evaluation assets that if unfulfilled could result in a loss of acreage (Note 17) and without future development could result in a decline in production and revenues with additional net cash used in operating activities.

The Company's ability to continue as a going concern is dependent upon its ability to generate net cash from operating activities and/or raise additional financing to meet its ongoing operational requirements and to fund its future development costs associated with exploration and evaluation assets and petroleum and natural gas properties development. There can be no assurances about generating net cash from operating activities or that additional financing will be available for the Company. This could result in a continued decline in production and revenues with additional net cash used in operating activities. These matters create material uncertainty that may cast significant doubt about the Company's ability to continue as a going concern. These financial statements do not give effect to adjustments that would be necessary to the carrying values and classification of assets and liabilities should the Company be unable to continue as a going concern. These adjustments could be material.

3. MATERIAL ACCOUNTING POLICIES

The accounting policies used to prepare these financial statements are consistent with those described in Note 3 of the Company's consolidated financial statements for the year ended March 31, 2024, with the exception of the adoption of the amendments to IAS 1 current liabilities. The Company adopted Amendments to IAS 1 Classification of Liabilities as Current or Non-current and Non-current Liabilities with Covenants effective April 1, 2024. The amendments did not have an impact on the interim condensed consolidated financial statements.

Accounts receivable, accounts payable, and joint venture payment plan balance are measured at amortized cost. These classifications are initially measured at fair value and subsequent revaluations are recorded at amortized cost using the effective interest method.

4. MANAGEMENT JUDGMENTS AND ESTIMATES

Critical judgments in applying accounting policies

The timely preparation of the financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities and income and expenses. Accordingly, actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Significant estimates and judgments made by management in the preparation of these financial statements are outlined below.

The economic climate may have significant adverse impacts on the Company, including material declines in revenue and cash flows, and related impacts to working capital levels and/or debt balances, which may also have a direct impact on the Company's operating results and financial position. These and other factors may adversely affect the Company's liquidity and the Company's ability to generate income and cash flows to meet the Company's current and future obligations. A full list of the critical judgments in applying accounting policies and key sources of estimation uncertainty can be found in Note 5 of the Company's consolidated financial statements for the year ended March 31, 2024.

5. EXPLORATION AND EVALUATION ASSETS ("E&E ASSETS")

($000s)		
Balance, March 31, 2023	**$**	**12,248**
Additions		77
Capitalized share-based compensation		1
Exchange adjustments		(333)
Balance, March 31, 2024	**$**	**11,993**
Additions		14
Capitalized share-based compensation		1
Exchange adjustments		134
Balance, December 31, 2024	**$**	**12,142**

A summary of E&E assets is shown in the table below:

($000s)		
ATP 732 / PCA 332 - Tookoonooka	$	7,500
PL 303 – Barta Block Cuisinier (controlling permit ATP 752)		2,506
ATP 934 – Barrolka		2,110
Other		26
Balance, December 31, 2024	**$**	**12,142**

Exploration and evaluation assets consist of the Company's exploration projects in Australia, which are pending the determination of proved or probable Reserves. Costs primarily consist of acquisition costs, geological and geophysical work, seismic and drilling, and completion costs until the drilling of wells is completed, and the results have been evaluated.

6. PROPERTY, PLANT AND EQUIPMENT ("PP&E")

($000s)	Petroleum and natural gas properties	Other assets	Right-of-use assets	Total
Cost:				
Balance, March 31, 2023	**57,176**	**347**	**143**	**57,666**
Additions	397	-	-	397
Capitalized share-based compensation	2	-	-	2
Research and development credit	(649)	-	-	(649)
Change in decommissioning and restoration liability	(1,662)	-	-	(1,662)
Exchange adjustments	(2,078)	-	-	(2,078)
Balance, March 31, 2024	**$ 53,186**	**$ 347**	**$ 143**	**$ 53,676**
Additions	56	-	-	56
Disposal of equipment	(265)	-	-	(265)
Exchange adjustments	822	-	-	822
Balance, December 31, 2024	**$ 53,799**	**$ 347**	**$ 143**	**$ 54,289**

($000s)	Petroleum and natural gas properties	Other assets	Right-of-use assets	Total
Accumulated depletion, depreciation and impairment loss:				
Balance, March 31, 2023	**22,547**	**332**	**121**	**23,000**
Depletion and depreciation	1,215	3	22	1,240
Impairment	11,588	-	-	11,588
Exchange adjustments	(1,143)	-	-	(1,143)
Balance, March 31, 2024	**$ 34,207**	**$ 335**	**$ 143**	**$ 34,685**
Depletion and depreciation	932	2	-	934
Exchange adjustments	589	(2)	-	587
Balance, December 31, 2024	**$ 35,728**	**$ 335**	**$ 143**	**$ 36,206**
($000s)				
Net carrying amount:				
Balance, March 31, 2024	$ 18,979	$ 12	$ -	$ 18,991
Balance, December 31, 2024	**$ 18,071**	**$ 12**	**$ -**	**$ 18,083**

As at December 31, 2024, there were no external or internal indicators of impairment. During the nine months ended December 31, 2024, the Company capitalized $0.1 million of general and administrative expenses (nine months ended December 31, 2023 - $0.1 million).

During the nine months ended December 31, 2024, the Company disposed of some of its surplus equipment with book cost of $0.3 million for net proceeds of $0.2 million.

At March 31, 2024 there was a decrease in reserves volumes associated with the Cuisinier field due to a change in development plans. Management considered the resulting decline in budgeted net cash flows as a potential indicator of impairment. In accessing the CGU's recoverable amount, management concluded that value in use ("VIU") was greater than fair value less cost to sell. Management measured the value in use of the Cuisinier field based on expected future cashflows discounted at rates between 9%-40% depending on inherent development risks. It was determined that the value in use exceeded the carrying value of the Company's petroleum and natural gas properties as at March 31, 2024, resulting in an impairment charge of $11.6 million.

The projected cash flows used in the VIU calculation were derived from a report on the Company's oil reserves which was prepared by GLJ Ltd., an independent qualified reserve evaluator, as of March 31,

2024. The following table details the forward pricing used in estimating the CGU's recoverable amounts as at March 31, 2024.

YEAR FORECAST	Brent ($Cdn/Bbl)	Exchange Rate[(1)] ($Cdn/$ US)	Brent[(2)] ($US/Bbl)
2024 Q2-Q4[(1)]	112.36	0.745	82.83
2025	109.03	0.755	81.50
2026	107.60	0.765	81.50
2027	109.03	0.765	82.58
2028	111.15	0.765	84.19
2029	113.41	0.765	85.90
2030	115.71	0.765	87.64
2031	117.99	0.765	89.37
2032	120.36	0.765	91.16
2033	122.76	0.765	92.98
2034+	125.21	0.765	+2%/yr

(1) Exchange rates used to generate the benchmark reference prices in this table.
(2) Crude oil pricing has been estimated by GLJ as Brent blend in US dollars. Historical futures contract price is an average of the daily settlement price of the near-month contract over the calendar month.

The calculation of depletion for the nine months ended December 31, 2024 included $19.8 million for estimated future development costs associated with proved and probable reserves in Australia (March 31, 2024 - $19.8 million).

7. JOINT VENTURE PAYMENT PLAN

On October 2, 2024, the Company entered into a financing agreement relating to outstanding and disputed joint venture payables of Australian $2,367,399 ("Joint Venture payment plan"). The terms of the loan stipulate repayment over 24 months with monthly payments of Australian $98,642, which include both principal and interest components. The interest expense is due on the last day of each month. The interest rate on this loan is set at 5.0% over the Westpac Bank Bill Swap Rate ("BBSW") and is compounded on a daily basis.

The loan was initially recognized at its fair value of $2.2 million, discounted using an effective interest rate based the BBSW rate at the agreement date plus 5.0%. The loan is measured at amortized cost using the effective interest method. As the BBSW changes, both the interest expense and the amortization of the loan would be affected. This financing arrangement is treated as a financial liability measured at amortized cost.

As at December 31, 2024, the principal balance was $1.7 million. Payments of $0.3 million have been made for the three months ended December 31, 2024. The current portion of the Joint Venture payment plan is $1.0 million as at December 31, 2024.

8. DECOMMISSIONING AND RESTORATION LIABILITY

Changes to decommissioning and restoration obligations were as follows:

($000s)		
Balance, March 31, 2023	**$**	**5,096**
Change in estimate		(1,662)
Accretion		178
Exchange adjustments		(135)
Balance, March 31, 2024	**$**	**3,477**
Accretion		113
Exchange adjustments		37
Balance, December 31, 2024	**$**	**3,627**

The Company's decommissioning liabilities result from ownership interests in petroleum and natural gas properties. The Company estimates the total unadjusted and uninflated cash flows required to settle its decommissioning and restoration costs at December 31, 2024 is approximately $3.3 million (March 31, 2024 – $3.2 million) which will be incurred between 2026 and 2064. At December 31, 2024, an inflation factor of 4.0% (March 31, 2024 – 4.0%) and a risk-free discount rate of 4.0% (March 31, 2024 – 4.0%) have been applied to the decommissioning and restoration liability.

9. SHARE CAPITAL

Authorized:

Unlimited number of common shares with no par value.
Unlimited number of preferred shares, of which none have been issued.

Issued:

The following provides a continuity of share capital:

	Number of common shares	Amount
Balance, March 31, 2024	**485,304,215**	**118,796**
Balance, December 31, 2024	**485,304,215**	**118,796**

10. SHARE-BASED COMPENSATION

The Company has a share option plan for directors, officers and employees of the Company whereby share options representing up to 10% of the issued and outstanding common shares can be granted by the Board of Directors. Share options are granted for a term of up to five years and vest one-third after the first year and one-third on each of the next two anniversary dates. The exercise price of each option equals the market price of the Company's common shares on the date of the grant.

Stock options granted under the plan can be exercised on a cashless basis, whereby the recipient receives a lesser amount of shares in lieu of paying the exercise price based on the deemed market price of the shares on the exercise date, and withholding taxes if the option holder so elects.

A summary of stock option activity is presented below:

	Options	Weighted average exercise price
Balance, March 31, 2023	10,920,000	0.08
Forfeited	(300,000)	0.11
Balance, March 31, 2024	**10,620,000**	**0.08**
Granted	1,500,000	0.03
Forfeited	(2,550,000)	0.08
Balance, December 31, 2024	**9,570,000**	**0.07**
Exercisable, December 31, 2024	**8,070,000**	**0.08**

Exercise Price	Number Outstanding	Remaining Life (years)	Number Exercisable
$0.00 to $0.03	1,500,000	4.7	-
$0.04 to $0.08	8,070,000	1.2	8,070,000
	9,570,000	**1.8**	**8,070,000**

There were options granted during fiscal 2025 (none were granted in fiscal 2024). The fair value of the options granted during the quarter ended December 31, 2024 of $0.01 per share was estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions and resulting values.

Share price on grant date	$0.02
Risk-free interest rate (%)	3.3
Expected life (years)	5
Expected volatility (%)	104
Forfeiture rate (%)	20

The fair value of the options granted during the quarter ended December 31, 2024 of $0.02 per share was estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions and resulting values.

Share price on grant date	$0.03
Risk-free interest rate (%)	3.0

Expected life (years)	5
Expected volatility (%)	102
Forfeiture rate (%)	20

11. REVENUE

Revenue from the sales of crude oil is based on the consideration specified in the Liquids Aggregation Agreement with the joint venture operator. The Company recognizes revenue when it transfers control of the product to the buyers, which, under the current Crude Oil Transportation Agreement, is generally at the time the Crude Oil purchasers obtain legal title of the crude oil when it is physically lifted onto a Crude Oil carrying vessel at the Port Bonython lifting facility. At the time of lifting, the transaction price is based on the average US Brent price and adjusted for quality and other factors specified in the Liquids Aggregation Agreement. The transaction price as prescribed in the Liquids Aggregation Agreement is a variable price based on the benchmark US Brent commodity price index and may be adjusted for quality, location, delivery method or other factors depending on the agreed-upon terms of the contract. The amount of revenue recorded can vary depending on the grade, quality, and quantity of crude oil transferred to the joint venture operator. Revenues are typically collected 60 days following delivery to Port Bonython. The Cuisinier Joint Venture has recently negotiated a revised Crude Oil Sales and Purchase Agreement ("COSPA") with corresponding transportation agreements effective January 1, 2025, through to December 31, 2025.

12. PER SHARE AMOUNTS

Income (loss) per share is calculated based on net income (loss) and the weighted-average number of common shares outstanding.

($000s except per share amounts)	**Three months ended December 31,**		**Nine months ended December 31,**	
	2024	2023	**2024**	**2023**
Net loss for the period	**(370)**	(504)	**(1,188)**	(1,081)
Weighted average number of common shares				
– basic (000s)	**485,304**	485,304	**485,304**	485,304
– diluted (000s)	**485,304**	485,304	**485,304**	485,304
Basic and diluted (loss) income per share	**$ (0.00)**	$ (0.00)	**$ (0.00)**	$ (0.00)

For the nine months ended December 31, 2024, 9,570,000 (nine months ended December 31, 2023 - 10,320,000) of the options were considered anti-dilutive.

13. FINANCE EXPENSE

($000s)	**Three months ended December 31,**		**Nine months ended December 31,**	
	2024	2023	**2024**	2023
Accretion on decommissioning liability	**39**	45	**113**	133
Interest expense (income)	**86**	(1)	**93**	7
	125	44	**206**	140

14. FINANCIAL RISK MANAGEMENT

The Company has exposure to credit, liquidity, and market risk from its use of financial instruments. This note presents information about the Company's exposure to these risks, the Company's objectives and policies and processes for measuring and managing risk.

The Board of Directors has overall responsibility for identifying the principal risks of the Company and ensuring the policies and procedures are in place to appropriately manage these risks. Bengal's management identifies, analyzes and monitors risks and considers the implication of the market condition in relation to the Company's activities.

(a) Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations and arises principally from Bengal's cash calls paid to joint venture partners and receivables from petroleum and natural gas marketers. As at December

31, 2024, Bengal's receivables consisted of $1.9 million (March 31, 2024 - $1.8 million) from joint venture partners (all of which has been collected subsequent to period end).

Bengal has a Liquids Aggregation Agreement with a purchaser and has not experienced any collection problems to date. Cash calls paid to Bengal's Australian joint venture partners are held in trust accounts by the partner until spent. Bengal attempts to mitigate the risk from joint venture receivables by approving significant spending by partners prior to expenditure and only paying the cash call shortly before the funds are to be spent.

The carrying amount of accounts receivable and cash and cash equivalents represents the maximum credit exposure. Bengal establishes an allowance for doubtful accounts as determined by management based on their assessment of collection. Bengal does not have an allowance for doubtful accounts as at December 31, 2024 (March 31, 2024 – $nil) and did not provide for any doubtful accounts, nor was it required to write-off any receivables during the nine months ended December 31, 2024.

Cash and cash equivalents, when held, consist of cash bank balances and guaranteed investment certificates redeemable at any time. Bengal manages the credit exposure related to guaranteed investments by selecting counterparties based on credit ratings and monitors all investments to ensure a stable return, avoiding complex investment vehicles with higher risk such as asset-backed commercial paper.

(b) Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including work commitments, as they are due. Bengal prepares an annual budget and updates forecasts for operating, financing and investing activities on an ongoing basis to ensure it will have sufficient liquidity to meet its liabilities when due.

Bengal's financial liabilities consist of trade and other payables and Joint Venture payment plan, totalling $3.1 million at December 31, 2024 (March 31, 2024 - $3.2 million). All of the trade and other payables are due in less than one year.

At December 31, 2024, the Company had positive working capital of $1.0 million (March 31, 2024 - $0.2 million), which the Company defines as total current assets less total current liabilities, excluding lease obligations and current portion of decommissioning obligations. The Company's working capital includes both accrued accounts receivable, accounts payable, and Joint Venture payment plan balances due to the Operator of the Cuisinier field. The Company does not have the legal right to offset these accounts and therefore there is a risk that the inability to collect on accrued receivables could impair Benga's ability to pay joint venture liabilities resulting in a default under the Cuisinier Joint Operating Agreement. This default could result in the Company losing some or all of its working interest in the Cuisinier field. The Company is managing its liquidity risk through its principal and interest payments. There is a risk if the Company's cash flows are insufficient to meet these obligations.

The Company also has significant capital work commitments associated with its exploration and evaluation assets that if unfulfilled could result in a loss of acreage (Note 17) and without future development could result in a decline in production and revenues with additional net cash used in operating activities.

The Company's ability to continue as a going concern is dependent upon its ability to generate net cash from operating activities and/or raise additional financing to meet its ongoing operational requirements and to fund its future development costs associated with exploration and evaluation assets and petroleum and natural gas properties development.

The majority of the Company's oil sales are benchmarked on US Brent prices. The Company incurs most of its expenditures in Australian dollars whereas the Company generates most of its revenues in US dollars. The Company is acting with its joint venture partners to reduce discretionary operational spending and limiting its capital expenditures capital towards lower risk projects that meet its internal economic hurdles and are expected to offer near-term cash flow upside.

(c) Market risk

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk comprises three types of risk: foreign currency risk, commodity price risk and interest rate risk. The Company is exposed to market risks resulting from fluctuations in foreign exchange rates, commodity prices and interest rates in the normal course of operations. A variety of derivative instruments may be used to reduce exposure to these risks.

Foreign Currency Risk

Foreign currency risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in foreign exchange rates. Bengal receives US dollars for Australian oil sales and incurs expenditures in Australian and Canadian currencies. The Company may enter into derivative foreign currency contracts in order to manage foreign currency risk but has not done so to date.

The table below shows the Company's exposure in Canadian dollar equivalent to foreign currencies for its financial instruments at December 31, 2024:

(in $000s CAD)	CAD$	AUS$	US$	Total
Cash and cash equivalents	$ 153	22	527	702
Accounts receivable	5	1	1,884	1,890
Trade and other payables	(438)	(969)	-	(1,407)
Joint Venture payment plan	-	(1,673)	-	(1,673)
	$ (280)	**$ (2,619)**	**$ 2,411**	**$ (488)**

Exchange rates as at	December 31, 2024	March 31, 2024
Number of CAD for 1 AUD	**0.89**	0.88
Number of CAD for 1 USD	**1.44**	1.35

Commodity Price Risk

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of a change in commodity prices. Commodity prices for petroleum and natural gas are impacted by not only the relationship between the Canadian and United States dollar, as outlined above, but also world economic events that dictate the levels of supply and demand. Australian oil prices are based on the US Brent reference price, which currently trades at a premium to WTI. The Company had no commodity price derivatives at December 31, 2024 and March 31, 2024.

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate risk on its cash and cash equivalents and the Joint Venture payment plan at December 31, 2024. Cash and cash equivalents is restricted to investments with a maturity of three months or less. The Joint Venture payment plan balance is tied to the BBSW as described in Note 7, which is variable. If the average interest rate were to increase or decrease by one percent, it is estimated that interest expense would change by approximately $5,900 for the three months ended December 31, 2024 assuming that the Joint Venture payment plan balance was outstanding for the full period. The Company had no interest rate derivatives at December 31, 2024 and March 31, 2024.

15. CAPITAL MANAGEMENT

The Company's policy is to maintain a sufficient capital base for the objectives of maintaining financial flexibility which will allow it to operate effectively and provide creditor and market confidence allowing for financing opportunities in support of future accretive capital projects.

The Company manages its capital structure and adjusts by continually monitoring its business conditions, including changes in economic conditions, the risk profile of its project inventory, the efficiencies of past investments, the efficiencies of forecasted investments and the timing of such investments, the forecasted cash balances, the forecasted commodity prices and resulting cash flow.

In order to maintain or adjust the capital structure, the Company may from time-to-time issue shares (if available on reasonable terms), issue debt instruments, sell assets, farm out properties and adjust its capital spending to manage current and projected cash levels. As disclosed in Note 2, there can be no assurance that equity or debt financing will be available or sufficient to meet capital commitments, or for other corporate purposes, or if equity or debt financing is available, that it will be on terms acceptable to the Company.

16. SUPPLEMENTAL CASH FLOW INFORMATION

Change in non-cash working capital items ($000s)	Three months ended December 31, 2024	2023	Nine months ended December 31, 2024	2023
Accounts receivable	**72**	677	**(108)**	(50)
Prepaids and deposits	**85**	(169)	**162**	(44)
Trade and other payables	**(1,751)**	213	**(1,771)**	108
Effect of change in foreign currency rates	**(34)**	(16)	**(40)**	17
	$ (1,628)	$ 705	**$ (1,757)**	$ 31

Attributed to:				
Operating	**275**	902	**(54)**	42
Investing	**(1,903)**	(197)	**(1,703)**	(11)
	$ (1,628)	$ 705	**$ (1,757)**	$ 31

The following represents the cash interest paid and received in each period:

Cash interest paid and received ($000s)	Three months ended December 31 2024	2023	Nine months ended December 31, 2024	2023
Cash interest paid	**66**	-	**72**	8
Cash interest received	**-**	-	**-**	-

17. COMMITMENTS

At December 31, 2024, the contractual obligations for which the Company is responsible are as follows:

Contractual obligations (000s)	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Office lease	**50**	23	27	-	-
Joint Venture payment plan	**1,973**	1,184	789	-	-
Decommissioning and restoration	**3,695**	-	794	-	2,901
	5,718	1,207	1,610	-	2,901

The Queensland Government regulatory authority granted the Company Authority to Prospect 934 ("ATP 934") under a revised work program on March 1, 2015. The Company consolidated its ownership of ATP 934, resulting in a 100% and 40% operating interest in the northern and southern block of this permit respectively in 2018. The work program consists of 260 km^2 of 3D seismic and up to three wells. In February 2023, the Company extended its ATP 732 permit and received a Potential Commercial Area (“PCA”) over 343 km^2. This included additional work commitments related to both ATP 732 and PCA 332 as outlined below. At December 31, 2024, the Company had the following capital work commitments:

Permit	Work Program	Obligation period ending	Estimated expenditure(net) (millions CAD$)[1]
ATP 934 – Onshore Australia	260 km^2 3D seismic and up to three wells	February 2027	7.9
ATP 732 – Onshore Australia	Geological and up to three wells	February 2029	6.8
PCA 332 – Onshore Australia	Initial Production testing	February 2029	3.9
PCA 332 – Onshore Australia	Extended Production testing	February 2035	2.3

(1) Translated at December 31, 2024 at an exchange rate of AUD$1.00 = CAD$0.8915.

18. SEGMENTED INFORMATION

As at December 31, 2024, the Company has two reportable operating segments being the Australian oil and gas operations and corporate. Revenue reported below represents revenue generated from external customers. There were no inter-segment sales in any of the reported periods. The accounting policies of the reportable segments are the same as the group's accounting policies. Segment profit represents the profit earned by each segment without allocation of directors' salaries, finance costs and income tax expense. This is the measure reported to the chief operating decision maker for the purposes of resource allocation and assessment of segment performance.

($000s) Nine months ended December 31, 2024	**Australia**	**Corporate**	**Total**
Revenue	**4,585**	**-**	**4,585**
Interest expense	**93**	**-**	**93**
Depletion and depreciation	**932**	**2**	**934**
Net (loss)	**(551)**	**(637)**	**(1,188)**
Exploration and evaluation expenditures	**14**	**-**	**14**
Property, plant and equipment expenditures	**56**	**-**	**56**
Disposition of equipment proceeds	**(193)**	**-**	**(193)**

($000s) Nine months ended December 31, 2023	**Australia**	**Corporate**	**Total**
Revenue	$ 5,218	$ -	$ 5,218
Interest expense	7	-	7
Depletion and depreciation	868	24	892
Net (loss)	(409)	(672)	(1,081)
Exploration and evaluation expenditures	51	-	51
Property, plant and equipment expenditures	346	-	346

($000s) Three months ended December 31, 2024	**Australia**	**Corporate**	**Total**
Revenue	**1,431**	**-**	**1,431**
Interest expense	**86**	**-**	**86**
Depletion and depreciation	**274**	**1**	**275**
Net (loss)	**(127)**	**(243)**	**(370)**
Exploration and evaluation expenditures	**-**	**-**	**-**
Property, plant and equipment expenditures	**12**	**-**	**12**
Disposition of equipment proceeds	**(110)**	**-**	**(110)**

($000s) Three months ended December 31, 2023	**Australia**	**Corporate**	**Total**
Revenue	1,609	-	**1,609**
Depletion and depreciation	299	8	**307**
Net (loss)	(283)	(221)	**(504)**
Exploration and evaluation expenditures	10	-	**10**
Property, plant and equipment expenditures	60	-	**60**

($000s) As at December 31, 2024	**Australia**	**Corporate**	**Total**
Exploration and evaluation assets	**12,142**	**-**	**12,142**
Property, plant and equipment	**18,077**	**6**	**18,083**
Total assets	**33,347**	**211**	**33,558**
Total liabilities	**6,269**	**438**	**6,707**
As at March 31, 2024	**Australia**	**Corporate**	**Total**
Exploration and evaluation assets	11,993	-	11,993
Property, plant and equipment	18,982	9	18,991
Total assets	34,106	255	34,361
Total liabilities	6,358	297	6,655

CORPORATE INFORMATION

AUDITORS
MNP LLP • Calgary, Canada

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Piper Alderman • Sydney, Australia

BANKERS
Royal Bank of Canada • Calgary, Canada
WestPac • Sydney, Australia

REGISTRAR AND TRANSFER AGENT
Computershare • Toronto, Canada

DIRECTORS
Chayan Chakrabarty
Dr. Brian J. Moss
Barry Herring
W. B. (Bill) Wheeler
R. Neal Grant

DISCLOSURE COMMITTEE
Chayan Chakrabarty
Jerrad Blanchard

AUDIT COMMITTEE
Barry Herring (Chairman)
W. B. (Bill) Wheeler
R. Neal Grant

RESERVES COMMITTEE
Dr. Brian J. Moss (Chairman)
Barry Herring
R. Neal Grant

COMPENSATION COMMITTEE
Dr. Brian J. Moss (Chairman)
Barry Herring
R. Neal Grant

GOVERNANCE AND NOMINATING COMMITTEE
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Dr. Brian J. Moss
Barry Herring

HEALTH, SAFETY AND ENVIRONMENT COMMITTEE
R. Neal Grant (Chairman)
W. B. (Bill) Wheeler
Dr. Brian J. Moss

OFFICERS
Chayan Chakrabarty, President & Chief Executive Officer
Richard N. Edgar, Executive Vice President
Jerrad Blanchard, Chief Financial Officer
Bruce Allford, Secretary

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