International Exploration & Production

Management's Discussion & Analysis

Three and Twelve Months Ended
March 31, 2021 and 2020

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 twelve months ended March 31, 2021.

This MD&A dated June 17, 2021 should be read in conjunction with the Company's consolidated financial statements and related notes for the years ended March 31, 2021 and 2020. The consolidated financial statements of the Company have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

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 Measures", "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, 2021 consolidated financial statements and other filings are available on SEDAR at www.sedar.com.

In the following discussion, the three months ended March 31, 2021 may be referred to as "fourth quarter of fiscal 2021", "Q4 fiscal 2021" "Q4 FY 2021", "current quarter", and "the quarter". The comparative three months ended March 31, 2020, may be referred to as "fourth quarter of fiscal 2020", "Q4 fiscal 2020" "Q4 FY 2020", and "prior year's quarter". The year ended March 31, 2021, may be referred to as "fiscal 2021", "current year", and "the year". The comparative year ended March 31, 2020, may be referred to as "the previous year", "prior year", and "fiscal 2020".

FOURTH QUARTER FISCAL 2021 SUMMARY

Financial Summary:

- **Long term debt -** On February 26, 2021, the Company completed its debt settlement transaction between its wholly-owned subsidiary Bengal Australia Ltd. Pty and Westpac Banking Corporation ("Westpac") under its secured credit facility (the "Credit Facility") whereby the total balance outstanding of US$ 12.5 million was settled in exchange for a payment of US $10.0 million resulting in a gain on redemption of $3.5 million. In conjunction with this, the Company entered into a recapitalization transaction with Texada Capital Management Ltd. The transaction included the issuance of 330,720,000 common shares of the Company at a price of $0.05 per share for total proceeds of $16.5 million, of which $12.6 million (being the Canadian dollar equivalent of US $10.0 million based on the daily average CAD$/USD$ foreign exchange rate published by the Bank of Canada as at February 24, 2021) were used as settlement payment to Westpac.

- **Reserves –**Bengal's independently evaluated Proved Plus Probable ("2P") reserves for the fiscal year ended March 31, 2021 are 5,789 thousand barrels of oil ("Mbbls") and Proved reserves are 2,163 Mbbls. The net present value (NPV_{10}, before tax) of Bengal's 2P reserves are $87.6 million, or $0.21 per share. The 2P after tax net asset value is $69.1 million
- **Sales revenue** – Crude oil sales revenue was $1.6 million in the fourth quarter of fiscal 2021, which is 40% higher than the $1.1 million recorded in Q4 fiscal 2020. Full year fiscal 2021 sales revenue was $5.2 million compared to $8.1 million for the full year fiscal 2020. The decrease in sales revenue during the current fiscal year was due to a combination of naturally declining production volumes and lower realized crude oil prices, which continued to be impacted by demand disruptions associated with the ongoing COVID-19 pandemic.
- **Hedging** – The Company negotiated a waiver of all financial covenants and hedging requirements contemplated in its Credit Facility after December 31, 2020, therefore there were no realized or unrealized gains or losses on financial instruments during the quarter ended March 31, 2021. During the 2021 fiscal year, the Company recorded an unrealized loss of $1.5 million on its derivative contracts due to increasing crude oil prices. Upon settlement of the derivative contracts, the Company realized a $1.0 million gain on financial instruments which represents a 94% increase from the $0.5 million gain realized in the previous fiscal year.

- **Funds from (used in) operations[1]** – Bengal used $0.2 million of funds in operations during Q4 fiscal 2021 compared to $0.0 million of funds used in Q4 fiscal 2020. For the full year fiscal 2021, the Company generated and used $0.3 million of funds from operations compared to $0.4 million of funds from operations generated in the prior fiscal year. The decrease in funds from operations during fiscal 2021 was driven primarily by lower sales revenue as described above.
- **Net income** – Bengal reported a net income of $3.0 million for the current quarter compared to a net loss of $2.2 million in the fourth quarter of fiscal 2020. For the full year fiscal 2021, the Company reported $3.9 million of net income compared to a net loss of $2.9 million in the prior year. Several non-operational items contributed to net income during the year that were absent in the comparative period, including $3.7 million of foreign exchange gains and a $3.5 million gain on the settlement of the Company's Credit Facility.
- **Adjusted net income[2]** – Bengal reported an adjusted net loss of $0.4 million for the current quarter and $1.9 million for the full year fiscal 2021. Net income is adjusted for unrealized gain (loss) on financial instruments, the unrealized foreign exchange gain (loss) for the period and the non-cash impairment of non-current assets and $3.5 million gain on settlement of the Company's Credit Facility described above.

Operational Summary:

- **Production volumes** – The Company's share of total production in the current quarter was 18,222 bbls of light crude oil, which is a 21% decline from the 23,117 bbls produced in the fourth quarter of fiscal 2020. The current quarter production averaged 202 bbls/day compared to 254 bbls/day produced in the fourth quarter of fiscal 2020. Full year fiscal 2021 saw total production of 80,530 bbls compared to 102,230 bbls for full year fiscal 2020. The full year fiscal 2021 production per day averaged 221 bbls compared to 279 bbls/day for the full year fiscal 2020. During fiscal 2021, capital activity for the Cuisinier field was focused on the water injection pilot program, which is currently being commissioned and has not yet realized its expected incremental increase in production. Production, therefore, experienced natural reservoir decline rates through the year.
- **Capital expenditures** – Bengal completed the construction of its water injection pilot project during the fourth quarter of fiscal 2021. Due to the impacts of the COVID-19 pandemic on both commodity prices and operational capacity, the 2021 drilling campaign has been postponed until fiscal 2022.

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, ATP 934 Barrolka, ATP 732 Tookoonooka, and four recently acquired 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.

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 PCA (Potential Commercial Area). PCAs have a life span of up to fifteen years. In the case of ATP 752, applications for PCAs 205 and 206 were made on the Barta block and approved by the Queensland regulatory authority based on: (a) the producing Cuisinier Oil Field offsetting and oil shows in the Murta zone; (b) the deeper Jurassic Birkhead zone in the Hudson 1, Koki 1 and Barta 1, which were previously drilled and abandoned, and (c) the evidence of structural continuity from the 3D seismic control acquired over the last few years. These applications include a commercial viability report that indicates the area is likely to be commercially viable within the applied term. This allows for extra time to commercialize the resource. A similar application was made and approved for PCA 155 on the Wompi block and approved. These PCA's remain a part of the ATP until expiry. If a discovery of oil or gas is made, an application for a petroleum lease is made to allow for production. PLs are granted for up to a thirty-year term. Bengal is a party to two PLs on the former ATP 752 Barta block, PL 303 and PL 1028, in addition to three PCAs, PCA 206, 207 Barta West and PCA 155 Wompi block-Nubba/Yilgarn. Bengal also acquired four PLs adjacent

[1] See "Non-IFRS Measurements" on page 16 of this MD&A

[2] See "Non-IFRS Measurements" on page 16 of this MD&A

to ATP 934 in Q2 FY 2020.

AUSTRALIA – Cooper Basin, Queensland

PL303 and PL 1028 Cuisinier (controlling permit ATP 752) (30.357% WI)

A pilot reservoir pressure maintenance scheme (water flood pilot) is now underway. This pilot well encountered mechanical disruptions during initial attempts to commence water injection, which have been addressed through additional water filtration at the injection site. The location of this pilot is in the southeast quadrant of the Cuisinier pool, with injection of water to take place at the Cuisinier 24 well. The broad nature of the Cuisinier structure combined with variable flank aquifer pressure support has resulted in pressure depletion within the central portion of the Cuisinier pool. The injection of produced formation water is anticipated to both increase production in up to four offsetting wells and reduce water handling charges. On establishing success of the pilot, the Joint Venture will begin a multi phase water injection scheme, targeted fracture stimulation and more commercially efficient development drilling.

Bengal will participate in the 3D seismic controlled Chef exploration drilling project, which has been proposed by the Joint Venture operator (Santos) and is expected to commence in calendar Q4 2021. This target is located in the north east portion of the block which is immediately adjacent to the Cook and Cocinero fields also operated by Santos. This will be the Company's first well drilled into the Jurassic age reservoirs of the Birkhead-Hutton formations which have proven to be prolific producers in the neighboring Cook and Cocinero fields.

ATP 934 Barrolka (100% WI)

ATP 934 is the Company's 100% owned natural gas exploration block. Bengal conducted extensive state-of-the-art geophysical work over and above common practice in analogous fields in the Cooper Basin. The outcome of the additional analysis provides the Company with a higher degree of confidence in the block's identified features and has focused exploration on the most likely prospects.

Bengal entered into an agreement with Santos in July of 2020 to farm-in on a portion of the ATP 934 block. This farm-out finances and de-risks the initial field exploration by the basin leading gas explorer, with whom Bengal has an existing and successful partnership at the Cuisinier field. Additionally, and of equal importance, the partnership offers extensive operating experience backed by Santos' recent exploration success in neighboring fields analogous to the joint venture's exploration targets. Santos will carry the drilling costs of one well to earn a 60% operated interest in the ATP 934 southern farm-out block, which represents 57.8% of the total block post April 2020 relinquishment. This well is currently scheduled for drilling in calendar Q4 2021 and if successful, Bengal would pay its 40% share of any well tie in costs to nearby gathering infrastructure.

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

The Company is currently finalizing a schedule of development plans for its recently acquired 100% working interest in four PLs near to ATP 934. While not currently producing, all PLs have existing wells indicating log pay, drill stem test ("DST") results and or gas production from the Permian formation. Bengal has identified four wells to be tested and re-completed for production in its first phase of development.

Specifically, this program is expected to include the following development activities; (a) recommissioning of a 26km pipeline to tie a previously producing Wareena liquids rich gas wells into a nearby compression station accessing the Eastern Australia local and export market; (b) work-over of the Ramses well that demonstrated both a Permian gas discovery and oil-zone completion in a cased well, which recovered 588 bbls/d of light crude oil, based on a 105-minute drill stem test. Upon completion of a successful test, this well is expected to be immediately equipped for production and the oil sold into the regional market; (c) work-over of the Ghina well to evaluate the previous Permian liquids rich gas discovery and assess the economics of tie-in and field recovery; and finally (d) twin drilling of the existing Karnak well that showed a liquids rich gas pay zone in the Permian formation. Bengal expect that with the application of advanced underbalanced drilling techniques now common place in the Cooper Basin, a successful new well could be immediately tied into nearby gathering infrastructure.

The 100% ownership of these assets presents an appraisal and development opportunity that will be operated by the Company and is seen not only to be complementary to our proven producing, non-operated Cuisinier asset, but also as a key stepping stone for Bengal's natural gas platform with immediate market access to an existing pipeline upon which future exploration growth through ATP 934 can be undertaken.

ATP 732 Tookoonooka (100% WI)

In June 2019, the Company applied for an amendment to the Later Work Program (LWP) for the third term of ATP 732 permit, On October 22, 2019, the Company received approval from the Queensland regulatory authority for an amended LWP for the third, four-year term commencing April 1, 2019 to March 31, 2023. The approved

LWP was revised to minimum activities of reprocessing seismic and inversion work with an estimated cost of $50K and geological and geophysical investigation at an estimated cost of $50K during the four-year term.

Using the extensive 2D and 3D seismic data the Company has acquired combined with the oil shows and oil recovery from the Caracal exploration well which was drilled and cased, the Company will be applying for a Potential Commercial Area (“PCA”) over a part of the remaining ATP 732 land block. If successful, the PCA area will be exempt from further relinquishment.

OPERATING SUMMARY

($000s except per share, %, volumes and operating netback amounts)		Three months ended March 31				Twelve months ended March 31		
		2021		2020		2021		2020
Oil revenue	$	1,601	$	1,140	$	5,234	$	8,103
Operating netback[1]	$	670	$	249	$	2,754	$	4,547
Cash from operations	$	70	$	27	$	301	$	1,129
Funds (used in) from operations[2]	$	(158)	$	(849)	$	(305)	$	461
Per share ($) (basic and diluted)	$	0.00	$	(0.01)	$	0.00	$	0.00
Net income (loss)	$	3,040	$	(2,196)	$	3,928	$	(2,896)
Per share ($) (basic and diluted)	$	0.01	$	(0.02)	$	0.03	$	(0.03)
Adjusted net income (loss)[3]	$	(489)	$	(1,111)	$	(1,876)	$	(1,125)
Per share ($) (basic and diluted)	$	(0.01)	$	(0.01)	$	(0.01)	$	(0.01)
Capital expenditures	$	533	$	(68)	$	1,254	$	2,035
Oil volumes (bbl/d)		202		254		221		279
Operating netback [1]($/bbl)	$	36.77	$	10.77	$	34.20	$	44.47

(1) Operating netback is a non-IFRS measure and includes realized gain (loss) on financial instruments. Operating netback per bbl is calculated by dividing revenue (including realized gain (loss) on financial instruments) less royalties and operating costs by the total production of the Company measured in bbls. A reconciliation of the measures can be found on page 7 of this MD&A.

(2) Funds from (used in) operations is a non-IFRS measure which is calculated by adding back all non-cash expense deductions to the net loss for the quarter and fiscal year. Funds from (used in) operations per share is a non-IFRS measure calculated as calculated by dividing funds from (used in) operations by weighted average basic and diluted shares outstanding for the periods disclosed. A reconciliation of the measures can be found in the table on page 16 of this MD&A.

(3) Adjusted net income (loss) and adjusted net income (loss) per share are non-IFRS measures. The comparable IFRS measure is net income (loss). A reconciliation of the two measures can be found in the table on page 16 of this MD&A.

(4) The above non-IFRS measures do not have any standardized meaning under GAAP (as that term is defined in National Instrument 52-107 Acceptable Accounting Principles and Auditing Standards) and therefore may not be comparable to similar measures presented by other issuers.

RESULTS OF OPERATIONS

Production	**Three months ended March 31**		**Twelve months ended March 31**	
	2021	**2020**	**2021**	**2020**
Oil production (bbls/d)	202	254	221	279
Oil production (bbls)	18,222	23,117	80,530	102,230

Production during the quarter and fiscal year ended March 31, 2021 decreased by approximately 21% compared to both fiscal Q4 2020 and the 2020 fiscal year. These decreases represent natural production declines at the Cuisinier field. In response to the uncertain commodity price environment of the past 12 months, all development activity at Cuisinier were deferred with the exception of the water injection pilot that is currently being finalized and has not yet added incremental production.

Revenue/Pricing

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

		Three months ended March 31		**Twelve months ended March 31**	
		2021	**2020**	**2021**	**2020**
	Oil lifting				
	Volume (000s bbls)	17.0	26.7	85.7	104.6
	Weighted average price ($US/bbl)	63.88	58.35	43.26	65.37
A.	Sales (CDN $000's)	1,390	2,337	5,028	9,378
	Pipeline oil				
	Volume (000s bbls), change	1.2	(3.5)	(4.7)	(2.40)
	Price ($US/bbl), change	9.90	(39.80)	39.56	(49.22)
B.	Net sales (CDN $000's)	211	(1,197)	206	(1,275)
A.+B.	Total oil sales (CDN $000s)	1,601	1,140	5,234	8,103

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 that 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 COVID-19 pandemic and corresponding decrease in crude oil demand has significantly impacted benchmark crude oil pricing during fiscal 2021. During Q4 fiscal 2021 and to the date of this report, benchmark pricing has stabilized and accordingly the impact of pricing on Bengal's "pipeline oil" is less significant than in prior quarters based on consistence between quarter ending and quarter average pricing.

The following table outlines average benchmark prices:

	Three months ended March 31		Twelve months ended March 31	
	2021	2020	2021	2020
Brent oil ($/bbl)	77.85	67.59	58.99	81.37
Brent oil (US$/bbl)	60.82	50.44	44.35	61.18
Number of CAD$ for 1 AUS$	0.99	0.88	0.95	0.91
Number of CAD$ for 1 US$	1.28	1.34	1.33	1.33

($000s)

Operating netbacks

	Three months ended March 31		Twelve months ended March 31	
	2021	2020	2021	2020
Oil sales	1,601	1,140	5,234	8,103
Realized gain on financial instruments	-	268	1,033	533
Royalties	(96)	(259)	(314)	(316)
Operating expenses	(835)	(900)	(3,199)	(3,773)
Operating netback	670	249	2,754	4,547
($/bbl)				
Oil sales	87.86	49.31	64.99	79.26
Realized gain on financial instruments	-	11.59	12.83	5.21
Royalties	(5.27)	(11.20)	(3.90)	(3.09)
Operating expenses	(45.92)	(38.93)	(39.72)	(36.91)
Operating netback	36.77	10.77	34.20	44.47

In Q4 fiscal 2021, operating netbacks were $0.7 million or $36.77/bbl compared to Q4 fiscal 2020 at $0.2 million or $10.77/bbl. The primary reason for the 169% increase in operating netbacks is improved realized pricing on crude oil sales, which more than offset production declines. For the full year fiscal 2021, operating netbacks were $2.8 million or $34.20/bbl compared to $4.5 million or $44.47/bbl in the prior fiscal year due to lower realized crude oil sales prices and decreased production that were not fully offset by reduced operating expenses and the realized gain on financial instruments.

Risk Management Activities

The Company negotiated a waiver of all financial covenants and hedging requirements contemplated in its Credit Facility after December 31, 2020, therefore there were no realized or unrealized gains or losses on financial instruments during the quarter ended March 31, 2021. During the 2021 fiscal year, the Company realized a $1.0 million gain on financial instruments which represents a 94% increase from the $0.5 million gain realized in the previous fiscal year.

Royalties

Royalties

	Three months ended March 31		Twelve months ended March 31	
	2021	**2020**	**2021**	**2020**
Royalty expense ($000s)	96	259	314	316
$/bbl	5.27	11.20	3.90	3.09
% of revenue	6	23	6	4

In Queensland Australia, oil royalties are based on a government-established rate which scales according to benchmark oil prices plus a Native Title royalty of 1%.

Royalties have been calculated to be 6% of oil sales for full year fiscal 2021 as compared to 4% for the full year fiscal 2020 due to the application of allowable operating costs deductions and lower benchmark crude prices in the prior year. The significant decrease in royalty expense for the Q4 fiscal 2021 compared to Q4 fiscal 2020 is due to a year-to-date adjustment made by the operator during Q4 fiscal 2020 to reflect the annual fiscal 2020 royalty expense, for which there was no corresponding adjustment in the current quarter.

Operating Expenses

($000s)
Operating expenses

	Three months ended March 31		Twelve months ended March 31	
	2021	**2020**	**2021**	**2020**
Production	214	251	568	792
Transportation	621	649	2,631	2,981
	835	900	3,199	3,773
Production - $/bbl	11.74	10.86	7.05	7.75
Transportation - $/bbl	34.08	28.07	32.67	29.16
	45.82	38.93	39.72	36.91

Operating expenses for the three months ended March 31, 2021, were 18% higher than the previous year's fiscal Q4 on a per barrel basis. For the entire fiscal year, operating expenses per barrel were 8% higher than the prior year. The increase in relative operating expense is due to a combination of factors including progressively increasing water handling charges which are classified as transportation, the fixed nature of certain operating expenditures that have not decreased consistently with production and lack of joint venture audit credits as compared to prior years. Bengal is addressing water handling costs through its water injection program that will use produced water to support pressure in neighboring wells, which is expected to both increase production and decrease water handling charges. Following the easement of travel restrictions associated with the COVID-19 pandemic, the Company will commence joint venture audit activities, which based on historical experience, may result in operating expense credits associated with the preceding two fiscal years.

General and Administrative (G&A) Expenses

($000s) G&A	Three months ended March 31 2021	 2020	Twelve months ended March 31 2021	 2020
Net G&A expenses	843	806	2,341	3,589
Capitalized G&A expenses	-	153	(7)	(286)
Total G&A expenses	843	959	2,334	3,303

Total G&A expenses in the fourth quarter fiscal 2021 were 12% lower than fiscal Q4 2020. The full year fiscal 2021 G&A expenses were 29% lower than the prior year. The decrease in G&A expenses represents the Company's continued efforts to reduce all discretionary spending and focus free cashflows on accretive development opportunities. These reductions were supported by the Canadian Federal Government's wage and rent subsidy programs, which were in place for the entire fiscal year of 2021 and partially offset by several one-time severance payments during fiscal Q4 2021.

Share-based Compensation ("SBC")

($000s) SBC	Three months ended March 31 2021	 2020	Twelve months ended March 31 2021	 2020
Expensed share-based compensation	3	6	9	28
Capitalized share-based compensation	-	-	-	1
	3	6	9	29

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, Depreciation and Amortization (DD&A)

($000s) DD&A	Three months ended March 31 2021	 2020	Twelve months ended March 31 2021	 2020
Petroleum and natural gas properties	293	188	1,285	1,343
Other assets	1	2	6	7
Right-of-use assets	7	12	42	47
	301	202	1,333	1,397
DD&A - $/bbl	16.08	8.13	15.96	13.14

The Company's proved plus probable (2P) reserve volumes at March 31, 2021, decreased by approximately 65,000 bbls compared to March 31, 2020. In addition, capital costs to develop 2P reserves at March 31, 2021, were $60.9 million compared to $59.7 million at March 31, 2020.

The increase in depletion per barrel for Q4 fiscal 2021 compared to the comparative period is a result of a decrease in production of 18,222 bbls in Q4 fiscal 2021 compared with 23,117 bbls in Q4 fiscal 2020, coupled with an one-time adjustment in Q4 fiscal 2020 on depletion expense.

Production for full year fiscal 2021 was 102,230 bbls compared to 108,731 bbls for the previous year contributing to a lower total depletion for fiscal 2021.

Impairment

($000s) **Impairment expense**	**Three months ended March 31**		**Twelve months ended March 31**	
	2021	**2020**	**2021**	**2020**
Exploration and evaluation assets	-	-	-	10
Petroleum and natural gas properties	-	626	-	636
	-	626	-	646

As at March 31, 2021, the Company concluded that there were no triggers for impairment on its E&E assets.

During Q4 fiscal 2020, the Company took an impairment charge of $0.6 million due to one development well, Cuisinier-27, deemed to be uneconomic following evaluation of the results of the five well drilling program.

Finance Expense

($000s) **Finance expense**	**Three months ended March 31**		**Twelve months ended March 31**	
	2021	**2020**	**2021**	**2020**
Interest income	(1)	(2)	(1)	(4)
Accretion expense on decommissioning and restoration liability	5	8	19	34
Interest on lease liability	2	3	10	14
Interest on Credit Facility	136	272	881	1,232
	142	281	909	1,276

Interest on the Credit Facility had initially been based on US dollar LIBOR + 3% margin. The revised Credit Facility amendment dated November 2018 increased the margin to 3.75% effective January 1, 2019. An amendment to the Credit Facility dated November 2019 further increased the margin to 3.95% effective November 5, 2019. See details of the Credit Facility below. Interest on credit facility during fiscal Q4 2021 was accrued to February 26, 2021 at which time Company completed a debt settlement transaction between its wholly-owned subsidiary Bengal Australia Ltd. Pty and Westpac under its secured credit facility.

CAPITAL EXPENDITURES

($000s) Capital expenditures	Three months ended March 31		Twelve months ended March 31	
	2021	2020	2021	2020
Geological and geophysical	63	62	196	263
Drilling	1	1	13	146
Completions	158	21	734	1,365
Acquisition	311	(152)	31	261
	533	(68)	1,254	2,035
Exploration and evaluation expenditures	61	-	61	22
Development and production expenditures	472	(68)	1,193	2,013
	533	(68)	1,254	2,035

The development and production expenditure of $1.3 million for the full year fiscal 2021 relates primarily to the water injection pilot program at the Cuisinier field. The $0.3 million of acquisition costs for the quarter ended March 31, 2021 represent closing costs associated with the Company's fiscal 2020 PL acquisitions billed in March 2021.

CREDIT FACILITY

On February 26, 2021, Company completed its debt settlement transaction between its wholly-owned subsidiary Bengal Australia Ltd. Pty and Westpac Banking Corporation ("Westpac") under its secured credit facility (the "Credit Facility") whereby the total balance outstanding of US$ 12.5 million was settled in exchange for a payment of US $10.0 million resulting in a gain on settlement of $3.5 million. In conjunction with this, the Company entered into a recapitalization transaction with Texada Capital Management Ltd. ("Texada"). The transaction included the issuance of 330,720,000 shares at a price of $0.05 per share for proceeds of $16.5 million, of which $12.6 million (corresponding to US $10.0 million at the transaction date) were used as settlement payment to Westpac.

SHARE CAPITAL

Trading history	Three months ended March 31		Twelve months ended March 31	
	2021	2020	2021	2020
High ($)	0.10	0.10	0.14	0.13
Low ($)	0.03	0.05	0.02	0.05
Close ($)	0.08	0.08	0.08	0.08
Volume (000s)	8,472	1,418	17,864	3,179
Shares outstanding (000s)	432,987	102,267	432,987	102,267
Weighted average shares outstanding (000s) - basic and diluted	227,205	102,267	133,073	102,267

At June 17, 2021, there were 432,986,694 common shares issued and outstanding, together with 13,716,667 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 lease liability and amounted to $2.0 million at March 31, 2021 (March 31, 2020 - $18.9 million).

At March 31, 2021, the Company had working capital of $4.3 million, including cash and short-term deposits of $4.5 million and restricted cash of $0.04 million, compared to a working capital deficiency of $14.4 million at March 31, 2020. The prior year's working capital deficiency was primarily a result of the Credit Facility of $17.7 million maturing in February 2021.

In February 2021, the Company raised $16.5 million on the issuance of common shares and extinguished the Credit Facility. Management anticipates that operating and capital requirements will be met out of working capital and operating cash flows.

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. To mitigate the net impact of low crude oil prices, the Company is acting with its joint venture partners to reduce discretionary spending and focus capital towards lower risk projects with near-term cash flow upside.

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 acquired an additional 21.43% working interest and received ministerial approval for the acquisition on August 11, 2015. In Q4 fiscal 2018, the Company consolidated its ownership of ATP 934 and now holds a 100% operating interest in this permit. The purchase consideration was AUS$0.3 million cash and potential future cash payments of up to AUS$1.0 million, which is made up of a AUS$0.2 million on certification by an independent competent person appointed by Bengal Energy (Australia) Pty Ltd. of not less than 25 billion cubic feet of proved reserves and AUS$0.8 million due upon the delivery of the first shipments of gas to market. The work program consists of 260 km^2 of 3D seismic and up to three wells.

At March 31, 2021, the Company had the following capital work commitments:

Country and permit	Work program	Obligation period ending	Estimated expenditure (net) (millions CAD$) (1)
Onshore Australia – ATP 934	260 km^2 3D seismic and up to three wells	February 2027	8.1(2)
Onshore Australia – ATP 732	Geological and geophysical studies	March 2023	0.1
Offshore Australia AC/RL 10	Geological and geophysical studies	March 2023	0.1

(1) Translated at March 31, 2021 at an exchange rate of AUS$1.00 = CAD$0.9578.

(2) The During fiscal 2021, the Company received confirmation that the commitment on ATP 934 was reduced in exchange for a 50% relinquishment of the non-potential acreage of ATP 934 at the end of the first term expiry date of February 28, 2021. During Q2 fiscal 2021, the Company entered into a farm-in agreement with Santos whereby Santos will pay 100% of the well costs of a one well work program with an estimated cost of AUS$2.7 million planned for the second half of calendar 2021. The $8.3 million of estimated expenditures is net of the estimated carried cost of AUS$2.7 million.

At March 31, 2021, the contractual obligations for which the Company is responsible are as follows:

($000s) Contractual obligations April 2021 to November 2054	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Office lease	278	97	181	-	-
Decommissioning and restoration	3,478	-	733	60	2,685
	3,756	97	914	60	2,685

OFF BALANCE SHEET TRANSACTIONS

The Company does not have any off balance sheet transactions.

SELECTED QUARTERLY INFORMATION

Fiscal quarter ($000s)	Mar 31 2021 **Q4 2021**	Dec 31 2020 Q3 2021	Sep 30 2020 Q2 2021	June 30 2020 Q1 2021	Mar 31 2020 Q4 2020	Dec 31 2019 Q3 2020	Sep 30 2019 Q2 2020	Jun 30 2019 Q1 2020
Oil sales	1,601	1,274	1,260	1,099	1,140	2,425	2,576	1,962
Cash flow from operations	70	62	(166)	335	27	259	527	316
Funds from (used in) operations(1)	(158)	130	(67)	(210)	(849)	599	724	(13)
Per share – basic and diluted ($)	0.00	0.00	(0.00)	0.00	(0.01)	0.01	0.01	0.00
Net income (loss)	3,040	670	(182)	400	(2,196)	556	(506)	(750)
Per share – basic and diluted ($)	0.01	0.01	(0.00)	0.00	(0.02)	0.01	(0.00)	(0.01)
Capital expenditures	533	498	124	99	(68)	346	477	1,280
Working capital (deficiency)	4,293	(15,068)	(15,129)	(14,908)	(14,434)	(13,823)	(14,120)	(13,964)
Total assets	44,246	41,914	41,138	41,097	39,572	41,391	40,849	40,373
Shares outstanding (000s)	432,987	102,267	102,267	102,267	102,267	102,267	102,267	102,267
Operations:								
Oil volumes (bbls/d)	202	211	231	238	254	280	333	249
Operating netback(1) ($/bbl)	36.77	42.37	27.15	31.60	10.77	59.68	53.78	49.01

(1) See "Non-IFRS Measurements" on page 16 of this MD&A.

Production over the last eight quarters peaked during the second quarter of fiscal 2020 (ended September 20, 2019) as all wells from the Company's 2019 fracture stimulation program came on line. Natural declines in the Cuisinier oil field have been responsible for the steady decline in production since this peak. Significant volatility in benchmark crude pricing materially reduced oil sales in the four quarters preceding fiscal Q4 2021.

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 not effective at March 31, 2021 due to 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 has limited 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 and for tax planning, tax provision and compilation of corporate tax returns.

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 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.

(a) Critical judgments in applying accounting policies

The following are the critical judgments, apart from those involving estimations (see below), that management has made in the process of applying the Company's accounting policies and that have the most significant effect on the amounts recognized in these financial statements.

Identification of Cash-generating units

Petroleum and natural gas properties are aggregated into cash-generating units, for the purpose of assessing recoverability, based on their ability to generate largely independent cash flows. By their nature, these estimates and assumptions are subject to measurement uncertainty and may impact the carrying value of the Company's assets in future periods.

Impairment indicators

At the end of each reporting period, the Company reviews the petroleum and natural gas properties for external or internal circumstances that indicate that the petroleum and natural gas properties may be impaired. For the purpose of impairment testing, assets are grouped together into cash generating units ("CGU"s) for the purpose of impairment testing, which is the lowest level at which there are identifiable cash inflows that are largely independent of the cash flows of other groups of assets. If any such indication of impairment exists, the Company makes an estimate of its recoverable amount. A CGU's recoverable amount is the higher of its fair value less costs to sell ("FVLCS") and its value in use ("VIU").

The application of the Company's accounting policy for exploration and evaluation, petroleum and natural gas properties required management to make certain judgments as to future events and circumstances as to whether economic quantities of reserves have been found.

(b) Key sources of uncertainty

The following are the key assumptions concerning the sources of estimation uncertainty at the end of the reporting period that have a significant risk of causing adjustments to the carrying amounts of assets and liabilities.

Decommissioning provisions

The Company estimates future remediation costs of production facilities, wells and pipelines at different stages of development and construction of assets or facilities. In most instances, removal of assets occurs many years into the future. This requires judgment regarding abandonment date, future environmental and regulatory legislation, the extent of reclamation activities, the engineering methodology for estimating cost, future removal technologies in determining the removal cost and liability-specific discount rates to determine the present value of these cash flows.

Impairment of petroleum and natural gas assets

Petroleum and natural gas properties are assessed for recoverability at a cash generating unit ("CGU") level. The determination of CGUs is subject to management judgements. Recoverability is assessed by comparing the carrying value of the asset to its recoverable amount, which is based on the higher of fair value of the assets less the cost to sell ("FVLCS") or value in use ("VIU").

The significant estimates used in the determination of the recoverable amount include the following:

- proved and probable oil and gas reserves and the related cash flows
- discount rates – the discount rates used to calculate the net present value of proved and probable oil and gas reserves may be influenced by changes in the general economic environment which could result in significant changes to the estimate

The estimate of proved plus probable oil and gas reserves and the related cash flows requires the expertise of independent third party reserve engineers and includes significant assumptions related to:

- Forecasted oil and gas commodity prices
- Forecasted production
- Forecasted operating costs
- Forecasted royalty costs
- Forecasted future development costs

Reserves

The estimate of proved and probable oil and gas reserves is integral to the calculation of the amount of depletion charged to the statement of operations and is also a key determinant in assessing whether the carrying value of any of the Company's petroleum and natural gas properties has been impaired. Changes in reported reserves can impact asset carrying values due to changes in expected future cash flows.

The Company's reserves are evaluated and reported on by independent reserve engineers at least annually in accordance with Canadian Securities Administrators' National Instrument 51-101– *Standards of Disclosure For Oil and Gas Activities ("NI-51-101")*. Reserve estimation is based on a variety of factors including engineering data, geological and geophysical data, projected future rates of production, forecasted oil and gas commodity prices, and timing of future expenditures, all of which are subject to significant judgment and interpretation.

Share-based payments

The Company measures the cost of its share-based payments to directors, officers, employees and certain consultants by reference to the fair value of the equity instruments at the date at which they are granted. The assumptions used in determining fair value include: share price, expected lives of options, risk-free rates of return, share price volatility and the estimated forfeiture rate. Changes to assumptions may have a material impact on the amounts presented.

Liquidity

As part of its capital management process, the Company prepares budgets and forecasts, which are used by management and the Board of Directors to direct and monitor the strategy and ongoing operations and liquidity of the Company. Budgets and forecasts are subject to significant judgment and estimates relating to activity levels, future cash flows and the timing thereof and other factors which may or may not be within the control of the Company. The current challenging economic climate may lead to adverse changes in cash flow or working capital levels, which may also have a direct impact on the Company's results and financial positions. These and other factors may adversely affect the Company's liquidity and the Company's ability to generate profits in the future.

NON-IFRS MEASUREMENTS

Within this MD&A, references are made to terms commonly used in the oil and gas industry. Operating netbacks, netbacks per share, funds from (used in) operations, funds from (used in) operations per share, adjusted net income and adjusted net income per share do not have any standardized meaning under IFRS and are referred to as non-IFRS measures. Operating netback equals total revenue (including realized gain (loss) on financial instruments) less royalties and operating expenses. Operating netback per barrel equals netback divided by the applicable number of barrels. Management utilizes these measures for operational performance. Funds from (used in) operations is a non-IFRS measure which is calculated by adding back all non-cash expense deductions to the net loss for the quarter and year. Funds from (used in) operations per share is a non-IFRS measure calculated as calculated by dividing funds from (used in) operations by weighted average basic and diluted shares outstanding for the periods disclosed Adjusted net income is a non-IFRS measure, which should not be considered an alternative to "Net income (loss)" as presented in the consolidated statement of income (loss) and comprehensive income (loss), and is presented in the Company's financial reports to assist management and investors in analyzing financial performance net of gains and losses outside of management's immediate control. Adjusted net income equals net income (loss) less unrealized gain (losses) on foreign exchange and unrealized gain (losses) on financial instruments plus non-cash impairment of non-current assets. Adjusted net income per share is calculated based on the weighted average number of common shares outstanding consistent with the calculation of earnings (loss) per share.

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.

The above non-IFRS measures do not have any standardized meaning under GAAP (as that term is defined in National Instrument 52-107 Acceptable Accounting Principles and Auditing Standards) and therefore may not be comparable to similar measures presented by other issuers.

The following table reconciles cash from operations to funds from (used in) operations, which is used in this MD&A:

($000s)	Three months ended March 31		Twelve months ended March 31	
	2021	**2020**	**2021**	**2020**
Cash from operating activities	70	27	301	1,127
Changes in non-cash working capital	(228)	(876)	(606)	(668)
Funds (used in) from operations	(158)	(849)	(305)	459

The following table reconciles net income (loss) to adjusted net income (loss), which is used in this MD&A:

($000s)	Three months ended March 31 2021	2020	Twelve months ended March 31 2021	2020
Net income (loss)	3,040	(2,196)	3,928	(2,896)
Unrealized (gain) loss on financial instruments	-	(1,760)	1,539	(1,290)
Unrealized foreign exchange (gain) loss	(39)	2,219	(3,853)	2,415
Gain on settlement of long-term debt	(3,490)	-	(3,490)	-
Non-cash impairment of non-current assets	-	626	-	646
Adjusted net loss	(489)	(1,111)	(1,876)	(1,125)

ABBREVIATIONS

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

bbl	-	barrel
bbls	-	barrels
bbls/d	-	barrels per day
$/bbl	-	dollars per barrel
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
Santos		Santos Ltd.
WI	-	working interest
YTD	-	year to date

RISK FACTORS

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 both Canada and Australia. 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.

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 below 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 below does not purport to be an exhaustive summary of the risks affecting Bengal.

Risks Relating to the COVID-19 Pandemic

In March 2020, the World Health Organization declared a global pandemic related to COVID-19. Governments worldwide, including those in Canada and Australia, have enacted emergency measures to combat the spread of the virus. These measures, which include the implementation of travel bans, self-imposed quarantine periods and social distancing, have caused material disruption to businesses globally, resulting in an economic slowdown. Governments and central banks have reacted with significant monetary and fiscal interventions designed to stabilize economic conditions; however, the success of these interventions is not currently determinable.

The Company is exposed to the risks relating to public health emergencies, including COVID-19, and related government responses which may have a material and adverse effect on the Company's business, financial condition and operations. The extent to which COVID-19 may impact the Company's business is uncertain and not currently determinable. In the event that the prevalence of COVID-19 continues to increase, governments may enact further measures or extend existing measures impacting the Company's operations, suppliers, customers, counterparties, shippers, partners, employee health, the availability and function of regulatory agencies, or the flow of labour`. The Company continues to monitor and is taking precautions to adhere to all applicable occupational health guidelines and all recommendations from applicable government agencies and public health authorities. Such measures and mandates may also increase the Company's expenses.

The duration and continued severity of the COVID-19 pandemic is uncertain, and may continue for a significant period of time.

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 as a result 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 widely in recent years. Global oil prices have recently been negatively impacted by oversupply and demand destruction associated with the COVID-19 pandemic. Any material decline in prices could result in a reduction of net production revenue. Certain wells or other projects may become uneconomic as a result 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 of 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 fund its ongoing activities at all times. From time to time, Bengal may require additional financing in order 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 as a result 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, 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, provincial 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.

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.

ADDITIONAL INFORMATION

Additional information relating to Bengal is filed on SEDAR and can be viewed at www.sedar.com. Information can also be obtained by contacting the Company at Bengal Energy Ltd., Suite 1110, 715 5th Avenue SW., Calgary, Alberta T2P 2X6, 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 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;*
- *Pipeline oil volume, sales and price estimates;*
- *The size of the oil and natural gas reserves;*
- *Bengal's drilling program and waterflood pilot;*
- *The belief that the Cooper Basin assets offer attractive upside potential for oil and gas;*
- *The expected timing of restarting the 2020 multi-well development and appraisal drilling campaign;*
- *The expected timing of the pilot reservoir maintenance scheme at the Cuisinier 24 well and the anticipated production increases resulting from the injection of produced formation water and future water flood expansion phases;*
- *The planned extended production tests on the Nubba gas discovery well and expected timing of tying in the well*
- *The expectation of placing the appropriate hedges on the Company’s production;*
- *The expected timing of the commencement of a pilot pressure maintenance scheme and the potential positive performance response of in the Cuisinier field;*
- *The timing of he extended production test on the Nubba gas discovery well on the Wompi block;*
- *The timing of the completion of the depth image processing completion on ATP 934;*
- *The possibility and timing of a third party farm in agreement on ATP 934 Barrolka;*
- *The possibility of additional reprocessing and acquisition of 2D and 3D seismic on ATP 934;*
- *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 operation cash flows and alternative forms of financing;*
- *Expectations regarding the Credit Facility and the results of discussions with Westpac;*
- *Bengal’s ability to finance its working capital deficiency and to source funds for the same;*
- *Treatment under governmental regulatory regimes and tax laws;*
- *Capital expenditures programs and estimates of costs;*
- *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 2020 and capital program;*
- *Anticipated adverse impacts on the Company's operating results, liquidity and financial position as a result of the current economic climate, and the expected persistence of depressed revenue and cash flow through 2021;*
- *Expectations that a firm agreement will be executed with a third party with an interest in farming-in on a portion of the ATP 934 block;*
- *The anticipated commercial viability of certain areas of the Barta block;*
- *The Company's plans to target future foreign operations in jurisdictions with known long-term oil and gas ventures; and*
- *The continued integration of subsurface data to select drilling locations.*

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;*
- *Uncertainties associated with the COVID-19 pandemic;*
- *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;*
- *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.*

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 (www.sedar.com) 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, 2020 (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 ("NI 51-101").

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 section 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.

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.

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