Yangarra Resources Ltd.
Management's Discussion and Analysis
For the three and nine months ended September 30, 2026

Management's discussion and analysis ("MD&A") of the financial condition and the results of operations should be read in conjunction with the Company's September 30, 2026 unaudited condensed interim consolidated financial statements and the December 31, 2025 audited consolidated financial statements, together with the accompanying notes.

Yangarra Resources Ltd. (the "Company" or "Yangarra") is a publicly-traded company involved in the production, exploration and development of resource properties in Western Canada. The address of the registered office is 1530, 715 – 5 Avenue SW, Calgary Alberta, T2P 2X6.

Additional information about Yangarra filed with Canadian securities commissions is available on-line at www.sedarplus.ca.

The MD&A has been prepared using information that is current to October 29, 2026.

The financial information presented herein has been prepared in accordance with IFRS Accounting Standards ("IFRS") as issued by the International Accounting Standards Board and interpretations of the IFRS Interpretations Committee. Throughout this discussion, percentage changes are calculated using numbers rounded to the decimal to which they appear. All references to dollar amounts are in Canadian dollars.

BOE Presentation

Production information is commonly reported in units of barrel of oil equivalent ("boe"). For purposes of computing such units, natural gas is converted to equivalent barrels of oil using a conversion factor of six thousand cubic feet to one barrel of oil. This conversion ratio of 6:1 is based on an energy equivalent wellhead value for the individual products. Such disclosure of boe may be misleading, particularly if used in isolation. Figures that are presented on a boe basis herein are calculated as the total aggregate amount for the period divided by boe production volumes for the period. Readers should be aware that historical results are not necessarily indicative of future performance.

Non–IFRS and Additional IFRS Measures

This document contains "funds flow from operations" or "FFO", which is an additional IFRS measure. This document also contains the terms "adjusted net debt", "netbacks" "adjusted EBITDA" and "capital expenditures", which are non-IFRS financial measures. The Company uses these measures to help evaluate its performance. These non-IFRS financial measures do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures presented by other issuers. Readers are cautioned that such financial measures should not be construed as alternatives to or more meaningful than the most directly comparable IFRS measures as indicators of the Company's performance.

Funds flow from operations ("FFO")

Yangarra's determination of FFO and FFO per share may not be comparable to that reported by other companies. Management uses FFO to analyze operating performance and leverage and considers FFO to be a key measure as it demonstrates the Company's ability to generate cash flow necessary to fund future capital investments and to repay debt, if applicable. FFO is calculated using cash flow from operating activities before changes in non-cash working capital and decommissioning costs incurred. Yangarra presents FFO per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of net income per share.

The following table reconciles FFO to cash flow from operating activities, which is the most directly comparable measure calculated in accordance with IFRS:

	2026 Q3	2025 Q3	Nine Months Ended 2026	Nine Months Ended 2025
Cash flow from operating activities	$ 20,868	$ 14,254	$ 65,886	$ 47,874
Decommissioning costs incurred	163	357	163	357
Changes in non-cash working capital	2,029	(1,430)	(103)	451
Funds flow from operations	$ 23,060	$ 13,181	$ 65,946	$ 48,682

Netbacks

The Company considers corporate netbacks to be a key measure that demonstrates Yangarra's profitability relative to current commodity prices. Corporate netbacks are comprised of operating, field operating and net income (loss) netbacks.

Yangarra calculates Field Operating netback as the average sales price of its commodities less royalties, operating costs and transportation expenses. Operating netback starts with Field Operating netback and subtracts realized gains (losses) on commodity contract settlements. To calculate the Net Income (Loss) netback, Yangarra takes the Operating netback and deducts general and administrative costs, cash and non-cash finance expenses, share-based compensation expense as well as depletion and depreciation charges, accretion expense, unrealized gains (losses) on financial instruments, any impairment or exploration and evaluation expense and deferred income taxes.

All in cash costs

All in cash costs is calculated as royalties, operating, transportation, general and administrative and cash finance expenses, per boe.

FFO margin and operating margin

FFO margin is calculated as the ratio of FFO per boe to sales price and operating margin is calculated as the ratio of operating netback to sales price.

Adjusted net debt

Yangarra defines Adjusted net debt as the sum of our existing credit facilities and accounts payable and accrued liabilities less accounts receivable, prepaid expenses and inventory. Yangarra uses Adjusted net debt to assess efficiency, liquidity and the general financial strength of the Company. The most directly comparable IFRS financial measure to Adjusted net debt is Bank Debt. The following table provides a calculation of adjusted net debt.

	Sep 30, 2026	Dec 31, 2025
Bank Debt	$ 126,052	$ 127,666
Accounts receivable	(35,192)	(31,748)
Prepaid expenses and inventory	(10,731)	(9,425)
Accounts payable and accrued liabilities	31,106	20,226
Adjusted net Debt	$ 111,235	$ 106,719

Adjusted earnings before interest, taxes, depletion and depreciation, amortization

Adjusted earnings before interest, taxes, depletion and depreciation, amortization ("Adjusted EBITDA") which represents EBITDA, excluding changes in the fair value of commodity contracts, is used to assess efficiency, liquidity and the general financial strength of the Company.

	2026 Q3	2025 Q3	Nine Months Ended 2026	Nine Months Ended 2025
Net income for the Period	$ 8,303	$ 2,294	$ 25,172	$ 14,455
Finance	2,961	2,627	8,233	7,794
Deferred tax expense	2,755	1,049	8,243	5,311
Depletion and depreciation	10,330	8,756	30,320	27,744
Change in fair value of commodity contracts	137	(262)	(1,800)	(2,949)
Adjusted EBITDA	$ 24,486	$ 14,464	$ 70,168	$ 52,355

Working capital surplus (deficit)

Working capital surplus (deficit) is the total of current assets less current liabilities and is used to assess efficiency, liquidity and the general financial strength of the Company.

Forward-looking Statements

This MD&A contains forward-looking statements and forward-looking information (collectively "forward-looking information") within the meaning of applicable securities laws relating to the Company's plans and other aspects of our anticipated future operations, management focus, strategies, financial, operating and production results and business opportunities. Forward-looking information typically uses words such as "anticipate", "believe", "continue", "sustain", "project", "expect", "forecast", "budget", "goal", "guidance", "plan", "objective", "strategy", "target", "intend" or similar words suggesting future outcomes, statements that actions, events or conditions "may", "would", "could" or "will" be taken or occur in the future, including, but not limited to, statements on potential completion techniques being considered. Statements relating to "reserves" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future. Forward-looking information in this MD&A includes information relating to, among other things, the Company's drilling and completion plans; the timing of wells being brought onstream; anticipated production levels, expected well performance and payback; and the Company's future drilling, completion, development and capital expenditure plans.

The forward-looking information is based on certain key expectations and assumptions made by our management, including expectations and assumptions concerning prevailing commodity prices, exchange rates, interest rates, applicable royalty rates and tax laws; future production rates and estimates of operating costs; performance of existing and future wells; reserve volumes; anticipated timing and results of capital expenditures; the success obtained in drilling new wells; the sufficiency of budgeted capital expenditures in carrying out planned activities; benefits to shareholders of our programs and initiatives, the timing, location and extent of future drilling operations; the state of the economy and the exploration and production business; results of operations; performance; business prospects and opportunities; the availability and cost of financing, labour and services; the impact of increasing competition; ability to efficiently integrate assets and employees acquired through acquisitions, ability to market oil and natural gas successfully and our ability to access capital.

Although we believe that the expectations and assumptions on which such forward-looking information is based are reasonable, undue reliance should not be placed on the forward-looking information because Yangarra can give no assurance that they will prove to be correct. Since forward-looking information addresses future events and conditions, by its very nature they involve inherent risks and uncertainties. Our

actual results, performance or achievement could differ materially from those expressed in, or implied by, the forward-looking information and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking information will transpire or occur, or if any of them do so, what benefits that we will derive therefrom. Management has included the above summary of assumptions and risks related to forward-looking information provided in this MD&A in order to provide security holders with a more complete perspective on our future operations and such information may not be appropriate for other purposes.

Readers are cautioned that the foregoing lists of factors are not exhaustive. Additional information on these and other factors that could affect our operations or financial results are included in reports on file with applicable securities regulatory authorities and may be accessed through the SEDAR+ website (www.sedarplus.ca).

These forward-looking statements are made as of the date of this MD&A and we disclaim any intent or obligation to update publicly any forward-looking information, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

Overview

Yangarra is a junior oil and gas company engaged in the exploration, development and production of natural gas and oil with operations in Western Canada, with a main focus on the Cardium and Belly River formations in Central Alberta, where the Company has extensive infrastructure and land holdings. Yangarra is dedicated to creating value for its shareholders through its commitment to a clear business strategy and performance objectives. The Company's strategy is to increase the value of its corporate assets through organic drilling and by assembling a large, focused land base in Central Alberta that features high-quality, long-life light oil and liquids-rich gas reserves. The Company has assembled a significant future drilling inventory and will strive to grow this inventory through drilling, geology and strategic acquisitions.

Third Quarter Highlights

- Funds flow from operations of $23.1 million ($0.20 per share – fully diluted), an increase of 75% from the same period in 2025
- Oil and gas revenue of $37.5 million, an increase of 54% from the same period in 2025
- Adjusted EBITDA of $24.5 million ($0.22 per share – fully diluted), an increase of 69% from the same period in 2025
- Net income of $8.3 million ($0.07 per share – fully diluted), an increase of 262% from the same period in 2025
- Average production of 10,111 boe/d (45% liquids), a 6% increase from the same period in 2025
- Operating costs of $9.57/boe (including $3.36/boe of transportation costs)
- Operating netback of $28.92/boe
- Operating margin of 72% and funds flow from operations margin of 62%
- G&A costs of $1.64/boe
- Royalties at 8% of oil and gas revenue
- All in cash costs of $16.72/boe
- Capital expenditures of $22.7 million
- Adjusted net debt to third quarter annualized funds flow from operations of 1.2 : 1
- Adjusted net debt of $111.2 million
- Retained earnings of $378.1 million
- Decommissioning liabilities of $18.2 million (discounted)

Operations Update

Yangarra drilled seven wells in Q3 2026 and completed four, leaving three wells drilled but uncompleted at quarter-end. Year-to-date, the Company has drilled 19 wells and completed 16. Of these wells, ten were in the Belly River formation and nine were Cardium wells. With the 2026 Cardium drilling program complete, all farm-in commitments have been satisfied, and the Company has earned all rights in the Cardium and Belly River in Chambers. The Company plans to focus on Belly River development for the winter program. Throughout the year, the Belly River well design has continued to evolve and Yangarra continues to assess the long-term impact on production from different well designs. The fourth quarter program will include three Belly River wells on the same pad utilizing three different well designs.

Financial Information

	2026 Q3	2025 Q3	Nine Months Ended 2026	Nine Months Ended 2025
Statements of Income and Comprehensive Income				
Petroleum & natural gas sales	$ 37,479	$ 24,401	$ 110,151	$ 88,055
Income before tax	$ 11,058	$ 3,343	$ 33,415	$ 19,766
Net income	$ 8,303	$ 2,294	$ 25,172	$ 14,455
Net income per share - basic	$ 0.08	$ 0.02	$ 0.24	$ 0.14
Net income per share - diluted	$ 0.07	$ 0.02	$ 0.22	$ 0.13
Statements of Cash Flow				
Funds flow from operations	$ 23,060	$ 13,181	$ 65,946	$ 48,682
Funds flow from operations per share - basic	$ 0.22	$ 0.13	$ 0.62	$ 0.48
Funds flow from operations per share - diluted	$ 0.20	$ 0.12	$ 0.59	$ 0.44
Cash flow from operating activities	$ 20,868	$ 14,254	$ 65,886	$ 47,874
Weighted average number of shares - basic	105,595	101,276	105,570	101,039
Weighted average number of shares - diluted	112,499	109,736	112,474	109,487

	September 30, 2026	December 31, 2025
Statements of Financial Position		
Property and equipment	$ 849,968	$ 810,189
Total assets	$ 940,741	$ 894,405
Working capital surplus (deficit)	$ 16,708	$ 20,537
Adjusted net debt	$ 111,235	$ 106,719
Shareholders equity	$ 618,286	$ 590,468

Business Environment

	2026 Q3	2025 Q3	Nine Months Ended 2026	Nine Months Ended 2025
Realized Pricing (Including realized commodity contracts)				
Light Crude Oil ($/bbl)	$ 115.49	$ 90.72	$ 113.75	$ 89.79
NGL ($/bbl)	$ 43.94	$ 38.66	$ 46.04	$ 40.80
Natural Gas ($/mcf)	$ 2.19	$ 1.26	$ 2.23	$ 1.78
Realized Pricing (Excluding commodity contracts)				
Light Crude Oil ($/bbl)	$ 117.03	$ 90.72	$ 118.70	$ 90.42
NGL ($/bbl)	$ 43.94	$ 38.26	$ 46.04	$ 41.22
Natural Gas ($/mcf)	$ 1.68	$ 0.81	$ 1.87	$ 1.66
Oil Price Benchmarks				
West Texas Intermediate ("WTI") (US$/bbl)	$ 85.79	$ 65.74	$ 84.51	$ 67.40
Edmonton Par ($/bbl)	$ 115.65	$ 85.29	$ 110.46	$ 87.87
Edmonton Par to WTI differential (US$/bbl)	$ (3.11)	$ (3.82)	$ (4.50)	$ (4.36)
Natural Gas Price Benchmarks				
AECO (5A - daily) gas ($/mcf)	$ 1.48	$ 0.60	$ 1.75	$ 1.42
Foreign Exchange				
Canadian Dollar/U.S. Exchange	0.71	0.73	0.72	0.72

Benchmark oil prices increased by 30% for Q3 2026, with the West Texas Intermediate ("WTI") reference price averaging US$85.79/bbl compared with US$65.74/bbl in the same period in 2025. For the nine months ended September 30, 2026, WTI prices were up 25% averaging US$84.51/bbl. Demand for crude oil is generally tied to global economic growth, but is also influenced by factors such as infrastructure, political instability, market uncertainty, weather conditions, government tariffs and the wars in Ukraine and the Middle East.

Edmonton par differentials to WTI narrowed in Q3 2026 when compared to Q3 2025, moving from a US$3.82/bbl differential in Q3 2025 to US$3.11/bbl in Q3 2026. In the nine months ended September 30, 2026, Edmonton par differentials widened from US$4.36/bbl in the 2025 period to US$4.50/bbl in the 2026 period. The Edmonton par reference price is denominated in Canadian dollars. Edmonton par is the closest reference price point for Yangarra's oil and therefore is the closest proxy to realized pricing.

When compared to the three and nine months ended September 30, 2025, realized pricing on oil earned in the 2026 periods increased by 29% and 31%, respectively, excluding commodity contracts, and increased by 27% and 27%, respectively, when the effects of commodity contracts are included. The increase in oil pricing is a direct result of increased WTI pricing.

When compared to the three and nine months ended September 30, 2025, liquids pricing earned in the 2026 periods increased by 15%, and 12%, respectively, excluding commodity contracts, and increased by 14% and 13%, respectively, when the effects of commodity contracts are included, due to higher condensate pricing which is linked to oil prices.

AECO natural gas prices increased by 147% to $1.48/mcf for the three months ended September 30, 2026 and by 23% to $1.75/mcf for the nine months ended September 30, 2026 as compared to the 2025 periods.

Results of Operations

Net petroleum and natural gas production, pricing and revenue

	2026 Q3	2025 Q3	Nine Months Ended 2026	Nine Months Ended 2025
Daily production volumes				
Natural Gas (mcf/d)	33,475	33,435	33,845	35,668
Light Crude Oil (bbl/d)	2,085	1,641	1,954	1,833
NGL's (bbl/d)	2,447	2,340	2,350	2,368
Combined (BOE/d 6:1)	10,111	9,554	9,945	10,146
Revenue				
Petroleum & natural gas sales	$ 37,479	$ 24,401	$ 110,151	$ 88,055
Realized gain (loss) on commodity contract settlement	1,285	1,452	638	559
Total sales	38,764	25,853	110,789	88,614
Royalty expense	(2,958)	(1,116)	(9,188)	(5,226)
Total Revenue - Net of royalties	$ 35,806	$ 24,737	$ 101,601	$ 83,388

Total sales in Q3 2026 increased by 50% to $38,764 from $25,853 in Q3 2025. The change is attributable to:

- A 45% increase in average product prices
- A 6% increase in production (on a boe basis)
- Realized gains on commodity contracts of $1,285 in Q3 2026 versus gains of $1,452 in Q3 2025

Total sales in the nine months ended September 30, 2026 increased by 25% to $110,789 from $88,614 in the same period 2025. The change is attributable to:

- A 28% increase in average product prices
- A 2% decrease in production (on a boe basis)
- Realized gains on commodity contracts of $638 versus gains of $559 in the 2025 period

Company Netbacks ($/boe)

	2026 Q3	2025 Q3	Nine Months Ended 2026	Nine Months Ended 2025
Sales price	$ 40.29	$ 27.76	$ 40.58	$ 31.79
Royalty expense	(3.18)	(1.27)	(3.38)	(1.89)
Production costs	(6.21)	(5.47)	(5.87)	(5.33)
Transportation costs	(3.36)	(3.18)	(3.40)	(3.30)
Field operating netback	27.54	17.84	27.93	21.27
Realized gain (loss) on commodity contract settlement	1.38	1.65	0.24	0.20
Operating netback	28.92	19.49	28.17	21.47
G&A	(1.64)	(1.62)	(1.45)	(1.39)
Cash finance expenses	(2.33)	(2.63)	(2.37)	(2.45)
Depletion and depreciation	(11.11)	(9.96)	(11.17)	(10.02)
Non Cash - finance expenses	(0.85)	(0.36)	(0.66)	(0.36)
Abandonment Expenses	(0.18)	(0.27)	(0.06)	(0.08)
Stock-based compensation	(0.78)	(1.15)	(0.80)	(1.10)
Unrealized gain (loss) on financial instruments	(0.15)	0.30	0.66	1.06
Deferred income tax	(2.96)	(1.19)	(3.04)	(1.92)
Net income netback	$ 8.92	$ 2.61	$ 9.28	$ 5.21

The overall average price earned by the Company in Q3 2026 was higher when compared to Q3 2025 as natural gas prices increased by 74%, oil prices increased by 27% and liquids prices increased by 14%. The average sales price increased by 45% in Q3 2026 when compared to Q3 2025.

Field netbacks increased by 54% in Q3 2026 and by 31% for the nine months ended September 30, 2026 due to higher realized pricing in the 2026 periods.

Operating netbacks increased by 48% in Q3 2026 and by 31% for the nine months ended September 30, 2026 when compared to the same periods in 2025 with minimal changes in realized commodity contracts.

Royalty Expense

	2026 Q3	2025 Q3	Nine Months Ended 2026	Nine Months Ended 2025
Royalty expense	$ 2,958	$ 1,116	$ 9,188	$ 5,226
Per BOE	$ 3.18	$ 1.27	$ 3.38	$ 1.89
As a % of sales (including commodity contracts)	8%	4%	8%	6%
As a % of sales (excluding commodity contracts)	8%	5%	8%	6%

Royalties were higher at $2,958 during Q3 2026 or 8% as a percentage of sales (excluding commodity contract settlements) and for the nine months ended September 30, 2026, royalties increased to $9,188 or 8% as a percentage of sales. The increase is a result of increased royalty rates due to higher commodity pricing.

Production and Transportation Costs

	2026 Q3	2025 Q3	Nine Months Ended 2026	Nine Months Ended 2025
Production costs	$ 5,776	$ 4,812	$ 15,942	$ 14,764
Per BOE	$ 6.21	$ 5.47	$ 5.87	$ 5.33
Transportation costs	$ 3,129	$ 2,795	$ 9,224	$ 9,136
Per BOE	$ 3.36	$ 3.18	$ 3.40	$ 3.30
Combined	$ 8,905	$ 7,607	$ 25,166	$ 23,900
Combined ($/BOE)	$ 9.57	$ 8.65	$ 9.27	$ 8.63

Production and transportation costs increased by 11% on a per boe basis in Q3 2026 and increased by 7% in the nine months ended September 30, 2026 as compared to the 2025 periods due to general inflation increases, including higher fuel costs.

Depletion and depreciation

	2026 Q3	2025 Q3	Nine Months Ended 2026	Nine Months Ended 2025
Depletion and depreciation	$ 10,330	$ 8,756	$ 30,320	$ 27,744
Per BOE	$ 11.11	$ 9.96	$ 11.17	$ 10.02

Depletion and depreciation expense is higher in the 2026 periods as compared to the 2025 periods due to an increase in the per boe depletion rate. The 2026 per boe depletion rates increased as compared to the 2025 rates due to a lower 2025 2P reserve base which was partially offset by lower finding and development costs.

General and administrative expenses ("G&A")

	2026 Q3	2025 Q3	Nine Months Ended 2026	Nine Months Ended 2025
Gross G&A expenses	$ 1,843	$ 1,621	$ 4,917	$ 4,505
G&A recoveries	(322)	(199)	(992)	(644)
Net G&A expenses	$ 1,521	$ 1,422	$ 3,925	$ 3,861
Per BOE	$ 1.64	$ 1.62	$ 1.45	$ 1.39

G&A for Q3 2026 increased 14% on a gross basis due to inflationary pressures but increased by 7% on a net basis due to increased recoveries when compared to Q3 2025. When compared to the nine months ended September 30, 2025, G&A increased by 9% on a gross basis due to cost pressures and increased by 2% on a net basis due to higher recoveries.

On a boe basis, for the three and nine months ended September 30, 2026, G&A increased by 1% and 4% respectively due to the higher costs in 2026.

Other expenses

	2026 Q3	2025 Q3	Nine Months Ended 2026	Nine Months Ended 2025
Cash Finance				
Cash interest and finance expense	$ 2,149	$ 2,293	$ 6,393	$ 6,711
Lease interest paid	18	18	49	67
Non-Cash Finance				
Accretion of decommissioning liability	165	177	484	460
Accretion of debt issue costs	629	133	1,307	538
Accretion on lease obligations	-	6	-	18
	$ 2,961	$ 2,627	$ 8,233	$ 7,794
Share-based compensation	$ 723	$ 1,010	$ 2,171	$ 3,038

Interest and financing fees include interest on the Company's bank debt (the average amount drawn in 2026 was $126,859) and bank debt servicing charges.

For the nine months ended September 30, 2026, if interest rates had been 1% lower with all other variables held constant, net income would have been $931 (2025 – $864) higher, due to lower interest expense. An equal and opposite impact would have occurred had interest rates been higher by the same amount. The Company had no interest rate contracts in place as at September 30, 2026.

During the nine months ended September 30, 2026, the Company issued 2,296 RSUs that vest equally over 3 years. The RSUs are exercisable in either cash or shares at the option of the Company. As it is the Company's intention to settle in shares, the RSUs are treated as share-based compensation with a fair value on the date of issue of $1.14 per RSU. The Company is no longer issuing new options under the Stock Option plan. All previously issued stock options will continue to vest and expire as per the agreements in place when they were originally issued.

During the nine months ended September 30, 2026, the Company recognized $2,171 (2025 – $3,038) of share-based compensation in the condensed interim consolidated statements of income and comprehensive income. During the nine months ended September 30, 2026, the Company capitalized $475 (2025 - $676) of share-based compensation to property and equipment.

Commodity price risk contracts

	2026 Q3	2025 Q3	Nine Months Ended 2026	Nine Months Ended 2025
Realized gain (loss) on commodity contract settlement	$ 1,285	$ 1,452	$ 638	$ 559
Change in fair value of commodity contracts	(137)	262	1,800	2,949
	$ 1,148	$ 1,714	$ 2,438	$ 3,508

As at September 30, 2026 the Company was committed to the following commodity price risk contracts:

Volume		Term	Reference	Type	Strike Price
Oil					
300	bbl/d	Oct 26	WTI-USD	Collar	USD $75.00 - $93.25
300	bbl/d	Oct 26	WTI-USD	Collar	USD $80.00 - $97.20
300	bbl/d	Nov 26	WTI-USD	Collar	USD $80.00 - $93.85
Natural Gas					
Q4 2026					
2,000	GJ/d	Oct 26	AECO - 7A	Swap	CAD $3.00
1,000	GJ/d	Oct 26	AECO - 7A	Swap	CAD $2.505
1,000	GJ/d	Oct 26	AECO - 7A	Swap	CAD $2.70
3,500	GJ/d	Oct 26	AECO - 7A	Swap	CAD $2.51
1,500	GJ/d	Oct 26 - Dec 26	AECO - 7A	Swap	CAD $3.05
1,500	GJ/d	Nov 26	AECO - 7A	Swap	CAD $2.92
2,000	GJ/d	Nov 26 - Dec 26	AECO - 7A	Swap	CAD $3.465
2,000	GJ/d	Nov 26 - Dec 26	AECO - 7A	Swap	CAD $3.55
2,000	GJ/d	Nov 26 - Dec 26	AECO - 7A	Swap	CAD $3.61
1,500	GJ/d	Dec 26	AECO - 7A	Swap	CAD $3.26
5,000	GJ/d	Oct 26 - Dec 26	AECO - 7A	Collar	CAD $2.00 - $4.40
2,000	GJ/d	Oct 26 - Dec 26	AECO - 7A	Collar	CAD $2.25 - $4.10
1,500	GJ/d	Oct 26 - Dec 26	AECO - 7A	Collar	CAD $2.00 - $3.85
500	GJ/d	Oct 26 - Dec 26	AECO - 7A	Collar	CAD $2.00 - $3.57
Q1 2027					
2,000	GJ/d	Jan 27 - Mar 27	AECO - 7A	Swap	CAD $3.465
2,000	GJ/d	Jan 27 - Mar 27	AECO - 7A	Swap	CAD $3.55
2,000	GJ/d	Jan 27 - Mar 27	AECO - 7A	Swap	CAD $3.61
3,000	GJ/d	Jan 27 - Mar 27	AECO - 7A	Swap	CAD $3.00
3,000	GJ/d	Jan 27 - Mar 27	AECO - 7A	Collar	CAD $2.25 - $4.35
3,000	mmbtu/d	Jan 27 - Mar 27	NYMEX	Collar	USD $3.25 - $6.50
3,000	mmbtu/d	Jan 27 - Mar 27	NYMEX	Collar	USD $3.25 - $7.83
Q2 2027					
3,000	GJ/d	Apr 27 - Jun 27	AECO - 7A	Swap	CAD $2.00
3,000	GJ/d	Apr 27 - Jun 27	AECO - 7A	Swap	CAD $2.00
3,000	mmbtu/d	Apr 27 - Jun 27	NYMEX	Swap	USD $2.93
3,000	GJ/d	Apr 27 - Jun 27	AECO - 7A	Collar	CAD $1.50 - $2.50
3,000	GJ/d	Apr 27 - Jun 27	AECO - 7A	Collar	CAD $1.50 - $2.37
3,000	mmbtu/d	Apr 27 - Jun 27	NYMEX	Collar	USD $2.50 - $3.43
Q3 2027					
3,000	mmbtu/d	Jul 27 - Sep 27	NYMEX	Swap	USD $3.12
3,000	mmbtu/d	Jul 27 - Sep 27	NYMEX	Swap	USD $3.13
3,000	GJ/d	Jul 27 - Sep 27	AECO - 7A	Swap	CAD $1.85
3,000	GJ/d	Jul 27 - Sep 27	AECO - 7A	Collar	CAD $1.00 - $2.45
3,000	mmbtu/d	Jul 27 - Sep 27	NYMEX	Collar	USD $2.50 - $3.98
3,000	mmbtu/d	Jul 27 - Sep 27	NYMEX	Collar	USD $2.50 - $3.95

As the Company had a limited valuation of derivatives in place as at September 30, 2026, the sensitivity of the fair value of a 10% volatility in commodity prices would have an immaterial impact on unrealized gains (losses) reported in the consolidated statements of income and comprehensive income.

Deferred Taxes

	2026 Q3	2025 Q3	Nine Months Ended 2026	Nine Months Ended 2025
Deferred tax expense	$ 2,755	$ 1,049	$ 8,243	$ 5,311

Yangarra did not pay income taxes in 2025 and does not expect to pay income taxes in 2026 or in the near future as it has sufficient tax pools to cover taxable income. Deferred tax expense is higher in the 2026 periods than in the 2025 periods due the use of more tax pools to eliminate taxable income in 2026.

Liquidity and Capital Resources

The following table summarizes the change in adjusted net debt during the periods presented:

	Nine Months ended September 30, 2026	Year ended December 31, 2025
Adjusted net debt - beginning of period	$ (106,719)	$ (103,147)
Funds flow from operations	$ 65,946	62,805
Additions to property and equipment	$ (67,960)	(57,947)
Decommissioning costs incurred	$ (163)	(799)
Additions to E&E Assets	$ -	(6,123)
Issuance of shares	$ -	882
Lease obligation repayment	$ (849)	(1,438)
Other	$ (1,490)	(952)
Adjusted net debt - end of period	$ (111,235)	$ (106,719)
Credit facility limit	$ 160,000	$ 140,000

As at September 30, 2026 the maximum amount available under the syndicated credit facility was $160,000 (December 31, 2025 – $140,000) comprised of a $140,000 (December 31, 2025 – $120,000) extendable revolving term credit facility and a $20,000 (December 31, 2025 – $20,000) operating facility. The amount available under these facilities is re-determined at least twice a year and is primarily based on the Company's oil and gas reserves, the syndicate of lending institutions' forecast commodity prices, the current economic environment and other factors as determined by the syndicate (the "Borrowing Base"). If the total advances made under the credit facilities are greater than the re-determined Borrowing Base, the Company has 60 days to repay any shortfall. The facilities last for a 364-day period and will be subject to the next 364-day extension by May 31, 2027. If not extended by May 31, 2027, the facilities will cease to revolve, and all outstanding balances will become repayable on May 31, 2028. The facilities are secured by a general security agreement over all assets of the Company.

As at September 30, 2026, the $126,052 (December 31, 2025 – $127,666) reported amount of bank debt was comprised of $8,095 (December 31, 2025 – $14,276) drawn on the operating facility and $120,000 (December 31, 2025 – $115,000) drawn on the revolving facility and net of unamortized transaction costs of $2,043 (December 31, 2025 – $1,610).

The Company is subject to a financial covenant requiring an adjusted working capital ratio above 1:1 (current assets plus the undrawn availability under the syndicated credit facility, divided by the current liabilities less the drawn and excluding unrealized commodity contracts). The Company was in compliance with this covenant as at September 30, 2026 and December 31, 2025. The facilities are secured by a general

security agreement over all assets of the Company. The Company is required to ensure that not less than 30% of the forecasted daily production for the next twelve-month period is hedged and subject to commodity swaps with a minimum of 15% of such forecasted production being subject to commodity swaps that are swaps only (as opposed to a combination of swaps, collars and/or puts/calls). The Company was in compliance with this covenant as at September 30, 2026 and December 31, 2025.

The total standby fees on the revolving facility range, depending on the debt to EBITDA ratio, between 200 bps to 400 bps on bank prime borrowings and between 300 bps and 500 bps on bankers' acceptances. The undrawn portion of the revolving facility is subject to a standby fee in the range of 75 bps to 125 bps.

During the nine months ended September 30, 2026, the weighted average effective interest rate for the bank debt was approximately 6.52% (nine months ended September 30, 2025 – 6.98%).

Capital Spending

Cash additions	2026 Q3	2025 Q3	Nine Months Ended 2026	Nine Months Ended 2025
Land, acquisitions and lease rentals	$ (27)	$ 3,052	$ (562)	$ 3,844
Drilling and completion	$ 20,091	7,695	$ 58,886	30,629
Geological and geophysical	$ -	-	$ 124	105
Equipment	$ 2,509	1,480	$ 8,819	9,596
Other asset additions	$ 174	213	$ 693	660
	$ 22,747	$ 12,440	$ 67,960	$ 44,834
Exploration & evaluation assets	$ -	$ -	$ -	$ -

During the nine months ended September 30, 2026, Yangarra drilled 19 wells and completed 16 wells.

Outlook

The Company's Board of Directors approved a capital budget of $80 million for 2026, enabling the drilling of up to 25 wells during the year with a continued emphasis on Belly River development.

Decommissioning Liabilities

As at September 30, 2026, the undiscounted decommissioning obligation associated with the Company's existing properties was estimated to be $24,600 for which $18,212 has been recorded using a discount rate of 2.74% - 4.30% and an inflation rate of 2% and an estimated weighted average timing of cash flows of 4.25 years.

Off Balance Sheet Arrangements

There were no off-balance sheet arrangements.

Share Capital

Details of changes in the number of outstanding equity instruments are detailed in the following table:

	Common Shares	Stock Options	Restricted Share Units
Balance - December 31, 2025	102,129	216	8,088
Granted	-	-	2,296
Vested	3,466	-	(3,466)
Forfeited	-	(15)	(14)
Balance - September 30, 2026	105,595	201	6,904

There has been no change to the number of outstanding equity instruments as of the date of this MD&A.

Contingency

In the normal conduct of operations, there are other pending claims by and against the Company. Litigation is subject to many uncertainties, and the outcome of individual matters is not predictable with assurance. In the opinion of management, based on the advice and information provided by its legal counsel, the final determination of these other litigations will not materially affect the Company's financial position or results of operations.

Contractual Obligations and Commitments

As at September 30, 2026 the contractual maturities of the Company's obligations are as follows:

	Carrying Amount	*Contractual Cash Flows*	*Less than 1 year*	*1-2 Years*	*2-5 Years*
Accounts payable and accrued liabilities	$ 31,106	$ 31,106	$ 31,106	$ –	$ –
Bank debt	126,052	128,095	–	128,095	–
Lease obligations	3,118	3,324	1,098	892	1,334
Other liabilities	794	794	–	–	794
Commodity contracts	70	70	70	–	–
	$ 161,140	$ 163,389	$ 32,274	$ 128,987	$ 2,128

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. A substantial portion of the Company's accounts receivable are with natural gas and liquids marketers and partners on joint operations in the oil and gas industry and are subject to normal industry credit risks.

Purchasers of the Company's natural gas and liquids are subject to credit review to minimize the risk of non-payment.

The maximum exposure to credit risk for accounts receivable by type of customer:

As at	*September 30, 2026*	*December 31, 2025*
Natural gas and liquids marketers	$ 16,694	$ 9,941
Partners on joint operations	9,360	13,275
Other	9,138	8,532
	$ 35,192	$ 31,748

The Company has not experienced any significant collection issues with its natural gas and liquids marketers. The majority of the revenue accruals and receivables from natural gas and liquids marketers were received in October 2026.

The Company's receivables are aged as follows:

As at	*September 30, 2026*	*December 31, 2025*
Under 30 days	$ 22,865	$ 14,856
30 to 60 days	128	4,322
60 to 90 days	173	277
Over 90 days	12,026	12,293
	$ 35,192	$ 31,748

Capital Resources

The Company's objective when managing capital is to maintain a flexible capital structure which will allow it to execute its capital expenditure program, which includes expenditures in oil and gas activities which may or may not be successful. Therefore, the Company monitors the level of risk incurred in its capital expenditures to balance the proportion of debt and equity in its capital structure.

The Company considers its capital structure to include shareholders' equity and debt:

	September 30, 2026	*December 31, 2025*
Shareholders' equity	$ 618,286	$ 590,468
Bank debt	$ 126,052	$ 127,666

The Company monitors capital based on annual cash from operations before changes in non-cash working capital and capital expenditure budgets, which are updated as necessary and are reviewed and periodically approved by the Board of Directors.

The Company manages its capital structure and makes adjustments by continually monitoring its business conditions including the current economic conditions, the risk characteristics of the Company's petroleum and natural gas assets, the depth of its investment opportunities, current and forecasted net debt levels, current and forecasted commodity prices and other facts that influence commodity prices and funds from operations such as quality and basis differentials, royalties, operating costs and transportation costs. In order to maintain or adjust the capital structure, the Company considers its forecasted cash from operations before changes in non-cash working capital while attempting to finance an acceptable capital expenditure program including acquisition opportunities, the current level of bank debt available from the Company's lender, the level of bank debt that may be attainable from its lender as a result of petroleum and natural gas reserve growth, the availability of other sources of debt with different characteristics than existing debt, the sale of assets, limiting the size of the capital expenditure program and the issue of new equity if available on favorable terms. At September 30, 2026 and December 31, 2025, the Company's capital structure was subject to banking covenants. No changes were made to the capital policy in 2026.

Selected Quarterly Financial Information

	2026 Q3($)	2026 Q2($)	2026 Q1($)	2025 Q4($)
Petroleum & natural gas sales	37,479	43,198	29,474	27,197
Net income	8,303	11,965	4,904	564
Net income per share – basic [(1)]	0.08	0.11	0.05	0.01
Net income per share – diluted [(1)]	0.07	0.11	0.04	0.01
Funds flow from operations	23,060	26,047	16,839	14,123
Funds flow from operations per share – basic [(1)]	0.22	0.25	0.16	0.14
Funds flow from operations per share –diluted [(1)]	0.20	0.23	0.15	0.13
Capital expenditures (including E&E)	22,747	23,171	22,042	19,235

	2025 Q3($)	2025 Q2($)	2025 Q1($)	2024 Q4($)
Petroleum & natural gas sales	24,401	29,507	34,147	30,961
Net income	2,294	6,773	5,388	3,884
Net income per share – basic [(1)]	0.02	0.07	0.05	0.04
Net income per share – diluted [(1)]	0.02	0.06	0.05	0.04
Funds flow from operations	13,181	15,499	20,002	16,210
Funds flow from operations per share – basic [(1)]	0.13	0.15	0.20	0.16
Funds flow from operations per share –diluted [(1)]	0.12	0.14	0.18	0.15
Capital expenditures (including E&E)	12,440	15,019	17,376	19,890

[(1)] Sum of quarterly per share figures may not add to annual per share figures due to rounding.

Quarterly activities

Fluctuations in quarterly revenues, net income and FFO over the last eight quarters are due primarily to the volatility in commodity prices and changes in sales volumes due to production growth and declines tied to the timing of drilling activity. The Company reduced capital expenditures on drilling and completions in 2024 until Q4 2025 due to weak natural gas prices and a corresponding decrease in petroleum and natural gas sales occurred. Production in 2025 included nine new wells that came on production during the year. The third quarter of 2025 was impacted by a third-party turn-around which reduced average production for the year. During the nine months ended September 30, 2026, Yangarra drilled 19 wells and completed 16 wells.

Business Risks and Uncertainties

The Company is exposed to several operational risks inherent in exploring, developing, producing and marketing light crude oil and natural gas. These inherent risks include: economic risk of finding and producing reserves at a reasonable cost; financial risk of marketing reserves at an acceptable price given current market conditions; cost of capital risk associated with securing the needed capital to carry out the Company's operations; risk of environment impact; and credit risk of non-payment for sales contracts and joint venture partners. Other than the risks described herein (including the risks and uncertainties listed in the Forward-Looking Statements section in this MD&A) the Company is also subject to the risk factors set forth in the most recently filed AIF of the Company available on SEDAR+ which can be accessed at www.sedarplus.ca

The Company attempts to control operating risks by maintaining a disciplined approach to implementation of its exploration and development programs. Exploration risks are managed by hiring experienced technical professionals and by concentrating exploration activity on reservoirs where the Company has experience and expertise. The Company also generates internal prospects and participates in projects where ownership interest is considered sufficient to minimize risk. Operational control allows the Company to manage costs, timing and sales of production and to ensure new production is brought on-stream in a timely manner. The Company maintains a comprehensive insurance program to reduce risk to an acceptable level and to protect it against significant losses.

Environmental Risks

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. Compliance with such legislation can require significant expenditures and a breach could result in the imposition of fines and penalties, some of which could be material. Senior management continually assesses new and existing regulatory requirements and environmental risks and determines the impact these risks might have on the Company, as well as the appropriate actions necessary to manage those risks. These assessments and the resulting policy decisions are discussed quarterly with the Board of Directors which evaluates the performance and effectiveness of the Company's environmental policies and programs.

The Company's environmental responsibilities include removing property, plant and equipment as well as reclaiming land and property to its original state, subsequent to the completion of oil and natural gas extraction activities. This requirement results in an asset retirement obligation that provides current recognition of estimated expenditures that will be incurred in the future. The Company's decommissioning liabilities are discussed in further detail under "Critical Accounting Estimates" below, as well as in note 7 of the Company's December 31, 2025 audited consolidated financial statements.

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

As at September 30, 2026, an evaluation of the effectiveness of the Company's disclosure controls and procedures, as defined under the rules adopted by the Canadian securities regulatory authorities, was carried out under the supervision and with the participation of Management, including the Chief Executive Officer ("CEO"), and the Chief Financial Officer ("CFO"). Based on this evaluation, the CEO and CFO concluded that, as at September 30, 2026, the design and operation of the Company's disclosure controls and procedures were effective in meeting all regulatory filing requirements.

Internal control over financial reporting ("ICFR") means a process designed by, or under the supervision of, an issuer's certifying officers, and effected by the issuer's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's Generally Accepted Accounting Principles ("GAAP") and includes those policies and procedures that:

(a) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the issuer;

(b) are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with the issuer's GAAP, and that receipts and expenditures of the issuer are being made only in accordance with authorizations of management and directors of the issuer; and

(c) are designed to provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the issuer's assets that could have a material effect on the annual financial statements or interim financial reports;

Management is responsible for establishing and maintaining adequate internal controls over financial reporting.

Management has conducted an evaluation of its internal controls over financial reporting and determined that as at September 30, 2026 the controls were effective to provide reasonable assurance regarding the reliability of financial reporting, and the preparation of financial statements for external reporting purposes. In May 2013, the Committee of Sponsoring Organizations of the Treadway Commission issued an updated Internal Control-Integrated Framework ("2013 Framework") replacing the Internal Control - Integrated Framework (1992). The control framework Yangarra's officers used to design the Company's ICFR is the 2013 Framework.

During the period beginning on July 1, 2026 and ending on September 30, 2026, there were no material changes to the Company's ICFR and the CEO and CFO have filed certifications with the Canadian securities regulators regarding the Company's 2026 public filing documents.

Critical Accounting Judgments and Estimates

The preparation of the consolidated financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions that affect reported amounts and presentation of assets, liabilities, revenues, expenses and disclosures of contingencies and commitments. Such estimates primarily relate to unsettled transactions and events at the statement of financial position date which are based on information available to management at each financial statement date. Actual results could differ from those estimated. Judgments, estimates and assumptions are continuously evaluated and are based on management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. There have been no changes to the Company's critical accounting judgments and estimates during the period ended September 30, 2026. Refer to Note 2 of the Company's December 31, 2025 audited consolidated financial statements.