HIGHWOOD
ASSET MANAGEMENT LTD.

MANAGEMENT'S DISCUSSION & ANALYSIS
FOR THE YEAR ENDED DECEMBER 31, 2025

March 16, 2026

Management's Discussion and Analysis

This management's discussion and analysis ("MD&A") of operating and financial results of Highwood Asset Management Ltd. ("Highwood" or the "Company") is dated March 16, 2026, and is based on currently available information. It should be read in conjunction with the audited consolidated financial statements and accompanying notes for the years ended December 31, 2025 and 2024 and the annual information form for the year ended December 31, 2025. Unless otherwise noted, all financial information is presented in Canadian dollars, and is in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board ("IFRS Accounting Standards"). Additional information can be found at www.sedarplus.ca and www.highwoodmgmt.com.

Highwood's management is responsible for the integrity of the information contained in this report and for the consistency between the MD&A and consolidated financial statements. In the preparation of the consolidated financial statements, estimates are necessary to make a determination of future values for certain assets and liabilities. Management believes these estimates have been based on careful judgments and have been properly presented. The consolidated financial statements have been prepared using policies and procedures established by management and fairly reflect Highwood's consolidated financial position and results of operations.

Refer to the end of the MD&A for commonly used abbreviations.

Readers should read "Forward-Looking Statements" at the end of the MD&A, which explains the basis for and limitations of statements throughout this report that are not historical facts and may be considered "forward-looking statements" under securities regulations.

The Company's common shares and warrants trade on the TSX Venture Exchange ("TSX-V") under the symbol "HAM" and "HAM.WT".

All figures in tables are stated in thousands of Canadian dollars, except operational and per share amounts or as noted.

Description of Business

The Company is engaged in ownership and oversight of various operations with a primary focus on oil and gas production, with operations also in midstream energy operations and metallic minerals. The Company's current focus is to advance the exploitation of its oil and gas properties in Alberta.

Corporate Highlights and Outlook

- Average corporate production of 5,040 boe/d in Q4 2025. Highwood expects Q1 2026 production to be approximately 6,000 boe/d, representing an increase of approximately 20% from Q4 2025.

- For the fourth quarter of 2025, Highwood delivered Adjusted EBITDA of $10.9 million ($0.72 per share) and adjusted funds flow of $10.6 million ($0.70 per share).(1)(2)

- Highwood continues to be encouraged by the results of the 102/13-02-043-06W5 (the **"13-02 well"**) and the 100/11-33-042-05W5 (the **"11-33 well"**) that were drilled and brought online in mid December. For the month of January 2026, both the 13-02 well and 11-33 well were recognized by multiple third parties as two of the top net oil wells in Alberta, based on production, with both wells exceeding 25,000 bbl of gross oil production. The 13-02 well and 11-33 well combined, averaged gross production of approximately 1,650 bbls/d light oil and 2,500 boe/d (80% liquids) including associated gas and natural gas liquids (1,450 bbls/d and 2,225 boe/d net). Both wells have remained strong in February averaging gross total production of approximately 2,100 boe/d (76% liquids, 1,860 boe/d net). In aggregate, the Company expects the wells to pay out in less than 3 months at current strip pricing.(1)(3)

- Highwood's top priority remains shareholder value, and the Company achieved growth in all reserve categories, including the addition of 3,371 Mboe of new Proved Developed Producing ("**PDP**") reserves. Overall PDP reserves increased 7% to 19,594 Mboe, Total Proved ("**1P**") reserves increased 7% to 39,600 Mboe and Total Proved plus Probable ("**2P**") reserves increased 9% to 66,441 Mboe. As a result of the increase in reserves, Highwood realized a PDP NAV of $7.96/share, 1P NAV of $22.39/share and 2P NAV of $41.23/share. (2)

- Highwood's hedging program helps mitigate volatility in commodity pricing with approximately 2,400 bbls/day and 1,400 bbls/day of oil hedged throughout 2026 and 2027, respectively, at an average contract price of approximately $94.00CAD/bbl and $91.00CAD/bbl (WTI-NYMEX). With the recent conflict in the Middle East and the resulting increase in oil prices, Highwood layered in approximately 350 bbls/day and 1,300 bbls/day of oil throughout 2026 and 2027, respectively, which is included in the volumes noted above. In addition, the Company has approximately 6,975GJ/day of natural gas hedged in 2026 at an average contract price of approximately $3.15/GJ (AECO). The Company realized a gain on commodity contracts of $3.1 million during the fourth quarter of 2025.

- The Company is focused on reducing Net Debt / EBITDA to increase flexibility for the Company moving forward. At December 31, 2025, Highwood had approximately $325 million in tax pools, including more than $100 million in non-capital losses. Highwood does not anticipate being cash taxable for approximately three years or more.

Notes to Highlights:

(1) See "Caution Respecting Reserves Information" and "Non-GAAP and other Specified Financial Measures".

(2) Basic shares at December 31, 2025 is 15,171,169 which includes shares held in trust. Fully diluted shares at December 31, 2025 is 15,599,131.

(3) Based on Management's projections (not Independent Qualified Reserves Evaluators' forecasts) and applying the following pricing assumptions: Actual pricing up to February 28, 2026 and thereafter, WTI: US$70.00/bbl; MSW Diff: US$3.50/bbl; AECO: C$1.75/GJ; 0.735 CAD/USD. Management projections are used in place of Independent Qualified Reserves Evaluators' forecasts as Management believes it provides investors with valuable information concerning the liquidity of the Company.

Operational Update

The 13-02 well and the 11-33 well are Belly River wells in the Wilson Creek area that were completed and brought onstream late in the fourth quarter of 2025. The 13-02 well and 11-33 well continue to deliver strong results with current combined gross production of approximately 2,050 boe/d (75-80% liquids, 1,800 boe/d net).

Highwood continues to be encouraged by the results from the Basal Belly River play within its portfolio and the recent successes reinforce the Company's confidence in our inventory. The Company currently carries 16.5 net booked and 13 net unbooked locations in Wilson Creek.

Highwood has drilled two booked gross (1.1 net) wells in the first quarter of 2026, with one booked gross (1.0 net) in Brazeau and 1 booked gross (0.1 net) in Wilson Creek. Subject to market conditions, Highwood plans to drill 4-7 wells in the Belly River horizon for the remainder of 2026, with the next drills currently planned for the summer of 2026. Prior to the next drill in Wilson Creek, which will be the summer of 2026, Highwood is planning to upgrade infrastructure in the area to support further development.

Outlook

The primary focus in the near-term is reducing leverage while continuing to focus on shareholder returns. Corporately, the Company is dedicated to growing Free Cash Flow, on a per share basis, while using prudent leverage to provide maximum flexibility for organic growth and/or other strategic M&A opportunities, with a longer-term goal to provide significant returns of capital to shareholders. Highwood will continue to review and assess opportunities which are accretive to the Company as Highwood seeks to grow its operations. The Company will also continue to assess land offerings in strategic areas where the Company sees significant growth opportunities.

2025 Performance to Guidance

The following is an evaluation of the Company's performance compared to its 2025 Guidance:

	2025 Initial Guidance(1)	**2025 Updated Guidance(2)**	**2025 Results**
Production	6.2-6.4 Mboe/d	5.2-5.4 Mboe/d	5,296 Mboe/d
Liquids mix	75%–78%	70%	~68%
Adjusted EBITDA(3)	$88-$92 million	-	$53.3 million
Capital Expenditures	$60–$65 million	-	$61 million
Operating Netback (per boe)(3)	$36–$38	-	$26.31
Net Debt / 2025 Exit EBITDA(3)	~0.8x	-	~1.8x

Notes:

(1) See news release dated November 14, 2024. Assumed the following commodity prices — WTI: US$70.00/bbl; WCS Diff: US$14.00/bbl; MSW Diff: US$3.50/bbl; AECO: C$2.00/GJ; 0.73 CAD/USD.

(2) See news release dated October 20, 2025 (reiterated November 14, 2025). Assumed the following commodity prices — WTI: US$65.00/bbl; WCS Diff: US$14.00/bbl; MSW Diff: US$3.50/bbl; AECO: C$2.00/GJ; 0.73 CAD/USD.

(3) See "*Non-GAAP and Other Specified Measures*".

The Company did not meet its guidance on Adjusted EBITDA, Operating Netback (per boe) and Net Debt / 2025 Exit EBITDA due lower than expected production and commodity pricing. The Company did not meet its Production and Liquids Mix guidance because of delays in, and reductions to, its 2025 capital program, unplanned third party outages in the third quarter of 2025, and underperformance of the Q1 2025 capital program.

ORGANIZATION OF THE MD&A

PART 1 – OUR BUSINESS AND STRATEGY

Overview

Highwood is a junior asset manager with a current focus primarily in the upstream oil and gas space, as well as midstream oil and gas. Highwood's intention is to eventually oversee various operations including Environmental, Social and Governance ("ESG") and other clean energy transition subsectors, which include metallic minerals, clean energy technologies, upstream and midstream oil & gas production & processing.

- ✓ **Shareholder Return Focus**

  Steering future accretive acquisitions and organic growth opportunities will be prudent for shareholder returns.

- ✓ **Prudent Debt Adjusted Cashflow per Share Growth**

  Highwood will focus on growing production through a combination of executing capital plans and acquisitions. Current focus of the capital plan will be on developing the core assets and focusing on locations with strong rates of return and payouts of less than a year.

- ✓ **Debt Reduction**

  Committed to reducing Highwood's leverage profile.

- ✓ **Sustainability**

  The Company is committed to having a positive impact in the communities in which its operates – setting up partnerships for long term successes.

PART 2 – SUMMARY OF CONSOLIDATED FINANCIAL RESULTS

Highwood Asset Management Ltd. – Consolidated Financial and Operating Highlights

(all tabular amounts expressed in $000's, except share numbers) (Canadian dollars)

	Three months ended December 31, 2025	Three months ended December 31, 2024	Year ended December 31, 2025	Year ended December 31, 2024
Financial				
Petroleum and natural gas sales	$ **21,463**	$ 33,775	$ **98,169**	$ 135,794
Transportation pipeline revenues	$ **534**	$ 621	$ **2,172**	$ 2,670
Total revenues, net of royalties and commodity contracts (1)	$ **25,392**	$ 21,167	$ **101,853**	$ 109,498
Income and comprehensive income	$ **5,719**	$ 1,914	$ **21,707**	$ 27,950
Funds flow from operations (7)	$ **8,973**	$ 16,791	$ **45,877**	$ 68,876
EBITDA(7)	$ **12,511**	$ 20,365	$ **55,340**	$ 80,760
Adjusted EBITDA (7)	$ **10,883**	$ 18,995	$ **53,286**	$ 79,144
Capital expenditures, net	$ **9,931**	$ 10,999	$ **59,578**	$ 66,451
Working capital deficit *(end of period)* (2) (7)			$ **(11,424)**	$ (7,113)
Net debt *(end of period)* (3) (7)			$ **116,723**	$ 97,832
Shareholders' equity *(end of period)*			**154,063**	132,087
Shares outstanding *(end of period)* (4)			**14,186**	14,671
Options outstanding *(end of period)*			**658**	415
Warrants outstanding *(end of period)*			**3,150**	3,150
Restricted share units outstanding *(end of period)*			**338**	215
Deferred share units outstanding *(end of period)*			**90**	50
Weighted-average basic shares outstanding *(end of period)* (4)			**14,443**	14,837
Weighted-average diluted shares outstanding *(end of period)* (4)			**14,871**	15,103
Operations (5)				
Production				
Crude oil *(bbls/d)*	**2,623**	3,638	**2,773**	3,580
NGL *(boe/d)*	**759**	775	**853**	752
Natural gas *(mcf/d)*	**9,943**	9,319	**10,020**	8,695
Total *(boe/d)*	**5,040**	5,966	**5,296**	5,781
Benchmark prices				
Crude oil				
Canadian Light *(Cdn$/bbl)*	**76.84**	93.03	**85.69**	98.10
Natural gas				
AECO *(Cdn$/mcf)*	**2.81**	1.81	**1.86**	1.37
Average realized prices (6)				
Crude oil *(Cdn$/bbl)*	**72.71**	91.63	**81.76**	93.82
NGL *(Cdn$/boe)*	**26.88**	29.51	**29.70**	31.76
Natural gas *(Cdn$/mcf)*	**2.23**	1.17	**1.68**	1.30
Operating netback *(per boe)* (7)	**22.67**	36.58	**26.31**	38.30

(1) Includes realized and unrealized gains and losses on commodity contracts.

(2) Working capital deficit excludes commodity contract asset of $12.5 million (December 31, 2024 – net asset of $1.0 million), current portion of decommissioning liability of $2.1 million (December 31, 2024 - $1.6 million) and current portion of lease liabilities of $211 thousand (December 31, 2024 - $317 thousand).

(3) Net debt consists of bank debt and working capital deficit excluding commodity contract assets and/or liabilities, current portion of decommissioning liabilities and lease liabilities.

(4) Shares outstanding is adjusted for treasury shares purchased and held in trust

(5) For a description of the boe conversion ratio, see "Basis of Barrel of Oil Equivalent".

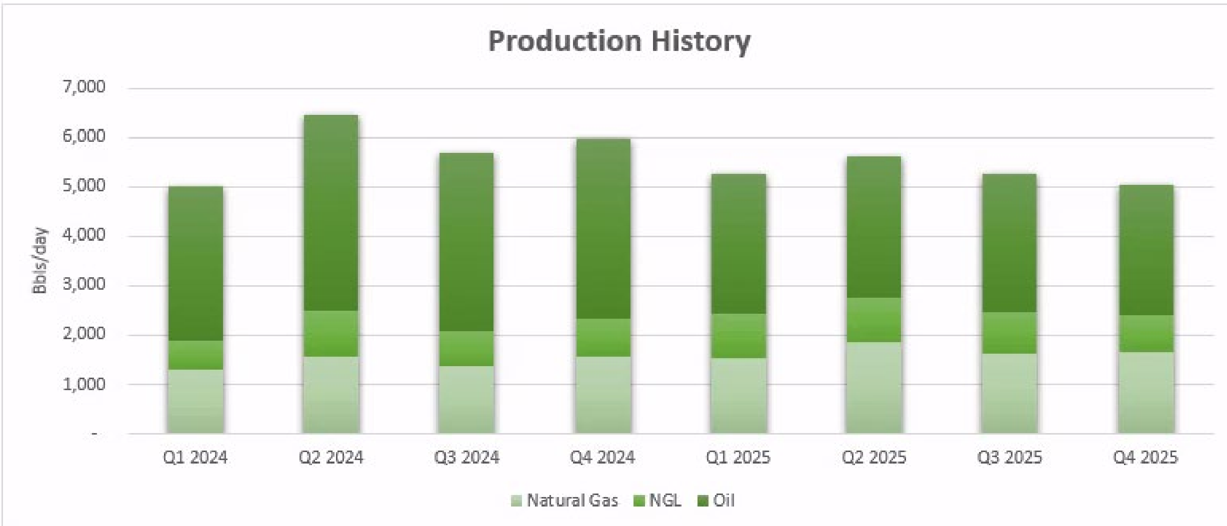
(6) Before hedging.

(7) See "Non-GAAP and other Specified Financial measures".

PART 3 – OPERATING RESULTS

Summary of Results

Production



	Three months ended December 31, 2025	2024	Year ended December 31, 2025	2024
Daily average volume				
Crude oil *(bbls/d)*	**2,623**	3,638	**2,773**	3,580
NGL (boe/d)	**759**	775	**853**	752
Natural gas (mcf/d)	**9,943**	9,319	**10,020**	8,695
Total sales *(boe/d)*	**5,040**	5,966	**5,296**	5,781
Total sales *(boe)*	**463,660**	548,904	**1,933,187**	2,115,689
Production weighting				
Crude oil and NGL	**67%**	74%	**68%**	75%

Overall production during the three months and year ended December 31, 2025 decreased by 16% and 9%, respectively, as compared to the same periods in 2024, mainly due to the overperformance of the drilling campaign in the first quarter of 2024 relative to 2025, along with natural declines. Overall, the production mix in the three months and year ended December 31, 2025 is ~ 68% liquids (three months and year ended December 31, 2024 ~75%).

During the current year, the Company executed a drilling campaign of ~$55 million. In total, the Company drilled 10 gross wells, bringing all of them on production. The two most successful wells drilled during the year, being the 11-33 and 13-02 wells, were drilled in the fourth quarter of 2025 and brought onstream in mid-late December.

Petroleum and Natural Gas Sales

	Three months ended December 31, 2025	2024	Year ended December 31, 2025	2024
Crude oil	**$ 17,546**	$ 30,672	**$ 82,766**	$ 122,913
NGL	**1,878**	2,104	**9,248**	8,740
Natural gas	**2,039**	999	**6,155**	4,141
Total	**$ 21,463**	$ 33,775	**$ 98,169**	$ 135,794
Average realized prices before hedging				
Crude oil *($/bbl)*	**72.71**	91.63	**81.76**	93.82
NGL *($/boe)*	**26.88**	29.51	**29.70**	31.76
Natural gas *($/mcf)*	**2.23**	1.17	**1.68**	1.30
Equivalent *($/boe)*	**46.29**	61.53	**50.78**	64.18

Overall petroleum and natural gas sales decreased for the three months and year ending December 31, 2025 compared to the same periods in 2024, driven primarily by a decrease in overall crude oil production as well as lower average realized commodity pricing related to crude oil and NGL's. The majority of Highwood's oil production is light oil and benchmarked to Edmonton light pricing while natural gas is benchmarked to AECO pricing. Edmonton light benchmark pricing decreased 17% and 13% for the three months and year ended December 31, 2025, compared to the same periods in 2024.

Western Canadian commodity prices continued to be volatile in 2024 and during 2025. In the short term, the Company anticipates continued price volatility. With respect to oil prices, significant factors include the unknown impact of transportation constraints in Alberta, tariffs, geopolitical issues, demand levels, as well as global inventory levels. The Company continues to monitor current and forecasted pricing.

Royalties

	Three months ended December 31, 2025	2024	Year ended December 31, 2025	2024
	$	$	**$**	$
Royalties	**3,954**	7,282	**20,623**	29,815
Per boe	**8.53**	13.27	**10.67**	14.09
Percentage of sales	**18.4%**	21.6%	**21.0%**	22.0%

Highwood's royalty burden includes crown, gross over-riding and freehold royalties applicable on the Company's production sales, which are either paid or taken in kind. The terms of the land and mineral rights owner agreements and provincial royalty regimes impact Highwood's overall royalty rate.

The decrease in overall royalties for the three months and year ended December 31, 2025 to the comparative periods in 2024 is driven by the lower petroleum and natural gas sales in the current year as compared to the prior periods, along with a lower average royalty rate.

During the three months and year ended December 31, 2025, royalties as a percentage of sales decreased as compared to the same periods last year, mainly due to lower average Crude Oil Royalty Calculation Par Prices (reference prices) as pre-determined by Alberta Energy and also by the impact of the two wells drilled in the fourth quarter of 2025. These wells generated additional Drilling and Completion Cost Allowance (C*) resulting in significantly lower royalties on production from those two wells.

The royalty rate is sensitive to commodity prices, and as such, a change in commodity pricing will impact the actual rate.

Operating and Transportation Expense

	Three months ended December 31,		Year ended December 31,	
	2025	2024	**2025**	2024
	$	$	**$**	$
Total operating and transportation	**7,258**	6,697	**27,846**	26,088
Per boe	**15.65**	12.20	**14.40**	12.33
Less midstream and other operating[1]	***(262)***	*(286)*	***(1,157)***	*(1,141)*
Upstream operating and transportation	**6,996**	6,411	**26,689**	24,947
Per boe	**15.09**	11.68	**13.81**	11.79

1) *Amounts removed are operating costs related to midstream operations or metallic minerals operations. The purpose is to show the operating cost associated with each barrel of production.*

During the three months and year ended December 31, 2025, total overall operating and transportation expenses increased as compared to the same periods last year, mainly due to active workovers, inflation and additional water disposal fees incurred during the current year. On a boe basis, total overall operating and transportation expenses increased as compared to the same periods last year, due to lower average production in the current periods creating fewer economies of scale with respect to fixed costs.

The midstream and other operating expenses mainly relate to the Wabasca River Pipeline System and EVI Terminal. These costs are removed from total operating and transportation expenses to show the operating and transportation costs associated with flowing barrels of production. Overall, these costs are fairly consistent year over year.

The Company has been actively working to reduce costs, by conducting abandonment and reclamation work on its non-producing properties, as well in other areas such as surface and mineral rentals. The Company is also assessing opportunities that are available with the Company's asset base to reduce operating and transportation costs and increasing operational efficiencies. This includes using infrastructure the Company owns rather than utilizing third parties for assets that were acquired within close proximity and taking over operatorship of assets.

Netback Analysis

	Three months ended December 31,		Year ended December 31,	
	2025	2024	**2025**	2024
	$/boe	$/boe	**$/boe**	$/boe
Average sales price	**46.29**	61.53	**50.78**	64.18
Royalties	**(8.53)**	(13.27)	**(10.67)**	(14.09)
Upstream Operating and transportation	**(15.09)**	(11.68)	**(13.81)**	(11.79)
Operating netback	**22.67**	36.58	**26.31**	38.30

Operating netback reflects the profit that is made from each barrel of production, which is why upstream operating and transportation expenses are used in the calculation. During the current periods, a significantly lower average sales price which is primarily driven by worldwide commodity pricing, has resulted in lower netbacks compared to the same periods in 2024. Management continues to look at ways to maximize the operating netback.

Transportation Pipeline Revenues

The Company owns an interest in the Wabasca River Sales Pipeline and EVI Terminal. Revenues are generated from a tariff charged to vendors who transport product on the pipeline. The EVI Terminal has a butane blending operation that generates revenues from the purchase and sale of butane. The EVI Terminal also has a heavy oil trucking facility which is currently not operational, however, the Company is assessing reactivating this portion of the terminal.

The Company's crude transmission line averaged throughput of 6,911M3/month and 7,389M3/month, respectively, during the three months and year ended December 31, 2025 (three months and year ended December 31, 2024 – 8,619M3/month and 9,095M3/month). Volumes were down during the current periods primarily due to third party production outages, particularly outages caused by wildfires throughout the second and third quarters of 2025 along with the related delays in third party restarts, as well as natural declines of the third-party producers' production.

	Three months ended December 31,		**Year ended December 31,**	
	2025	2024	**2025**	2024
Transportation pipeline revenues	**$ 534**	$ 621	**$ 2,172**	$ 2,670

Overall, the decrease in transportation pipeline revenues in the current periods is partly due to the decreased volumes throughout the second, third, and fourth quarters of 2025 along with the related delays in third-party restarts, as well as natural declines of the third-party producers' production. Additionally, in the first quarter of 2025, an internal line inspection was conducted which resulted in a temporary shutdown of the pipeline which impacted the revenues for the remainder of the year. Transportation pipeline revenues are generated on a tariff of $24.50/M3 of crude oil that is flowed through the pipeline.

Metallic Minerals

The metallic minerals segment includes industrial metal and mineral assets. During 2021, the Company amassed industrial metallic and mineral permits covering over 3.8 million acres in Alberta and British Columbia and issued its first National Instrument 43-101 Technical Report on Lithium from Brine on July 16, 2021 and an additional 43-101 Technical Report over the Ironstone prospective permits held by the Company on September 21, 2021. The Company also engaged the third-party resource evaluator to compile a 43-101 Resource Assessment specific to Drumheller, Alberta over the Lithium Brine prospective permits, which was completed February 21, 2022.

During the three months and year ended December 31, 2025, the Company incurred capital expenditures of $nil and $1.4 million, respectively (three months and year ended December 31, 2024, $nil and $1.4 million, respectively). The costs in 2025 related to extending the leases and the costs in 2024 related to converting the majority of the industrial metallic and mineral permits into leases.

As the metallic minerals segment entails early-stage exploration projects, there was no revenue and minimal operating expenses associated with the segment for the three months and year ended December 31, 2025 and 2024.

As Highwood assesses additional information on its lithium Sub-properties, Highwood will continue to evaluate value maximization paths for its lithium assets including a potential public pure play, low carbon intensity lithium company spinout. In the event that the Company, or a spinout of the Company, is successful in raising funds through an equity raise that is being contemplated, the Company plans, and may be required, under the equity raise to outlay significant exploration capital in the near future.

Extraction technologies continue to be evaluated as well as potential go forward technology parties whom Highwood may elect to partner with moving forward.

PART 4 – SELECT CONSOLIDATED FINANCIAL DISCLOSURES

Risk Management

Highwood's cash flow fluctuates as oil and natural gas are commodities whose prices are determined by worldwide and/or regional supply and demand, transportation constraints, weather conditions, availability of alternative energy sources and other factors, all of which are beyond Highwood's control. World prices for oil and natural gas have been very volatile in recent months and are inherently volatile.

Management of cash flow variability is an integral component of the Company's business strategy. Business conditions are monitored regularly and reviewed with the Board of Directors to establish risk management guidelines used by management in carrying out the Company's strategic risk management program.

The Company has elected not to use hedge accounting and, accordingly, the fair value of the financial contracts is recorded at each period-end. The fair value may change substantially from period to period depending on commodity forward strip prices for the financial contracts outstanding at the statement of financial position date. The change in fair value from period-end to period-end is reflected in the income for that period. As a result, income may fluctuate considerably.

The Company has the following commodity contracts outstanding at December 31, 2025 as required under the ARCA:

Swaps:

Product	Notional Volume	Term	Contract Price (CAD/GJ)	Index
Natural Gas	1,500GJ/day	April 1, 2025 to December 31, 2026	$ 3.13 - $ 3.20	AECO
Natural Gas	300GJ/day	November 1, 2025 to March 31, 2026	$ 3.50	AECO
Natural Gas	3,000GJ/day	April 1, 2025 to March 31, 2027	$ 3.15 - $ 3.40	AECO
Natural Gas	400GJ/day	May 1, 2025 to March 31, 2028	$ 3.00	AECO
Natural Gas	400GJ/day	July 1, 2025 to March 31, 2028	$ 3.05	AECO
Natural Gas	1,200GJ/day	November 1, 2025 to March 31, 2028	$ 3.00 - $ 3.02	AECO
Natural Gas	400GJ/day	October 1, 2025 to March 31, 2028	$ 3.01	AECO
Natural Gas	400GJ/day	January 1, 2027 to March 31, 2028	$ 3.09	AECO

Product	Notional Volume	Term	Contract Price (CAD/bbl)	Index
Crude Oil	100bbls/day	October 1, 2024 to March 31, 2026	$ 96.50	WTI - NYMEX
Crude Oil	100bbls/day	November 1, 2024 to March 31, 2026	$ 95.00	WTI - NYMEX
Crude Oil	100bbls/day	February 1, 2025 to December 31, 2026	93.00	WTI - NYMEX
Crude Oil	300bbls/day	April 1, 2025 to December 31, 2026	$ 93.00 - $ 93.31	WTI - NYMEX
Crude Oil	100bbls/day	July 1, 2025 to March 31, 2026	$ 91.15	WTI - NYMEX
Crude Oil	100bbls/day	July 1, 2025 to June 30, 2026	$ 91.50	WTI - NYMEX
Crude Oil	100bbls/day	October 1, 2025 to March 31, 2026	$ 97.00	WTI - NYMEX
Crude Oil	100bbls/day	October 1, 2025 to September 30, 2026	$ 93.00	WTI - NYMEX
Crude Oil	400bbls/day	October 1, 2025 to December 31, 2026	$ 92.00 - $ 94.00	WTI - NYMEX
Crude Oil	600bbls/day	January 1, 2026 to December 31, 2026	$ 90.50 - $ 96.00	WTI – NYMEX

Product	Notional Volume	Term	Contract Price (USD/bbl)	Index
Crude Oil	200bbls/day	January 1, 2026 to December 31, 2026	$ 66.00	WTI - NYMEX
Crude Oil	300bbls/day	April 1, 2026 to March 31, 2027	$ 65.00 - $ 66.00	WTI - NYMEX

Product	Notional Volume	Term	Contract Price (CAD/bbl)	Index
MSW Differential	1,000bbls/day	January 1, 2026 to December 31, 2026	$ 5.50 - $ 6.75	TMX-1A-SW

Electricity:

Product	Notional Volume	Term	Contract Price (CAD/MWh)	Index
Electricity	500 MWh/month	September 1, 2024 to July 31, 2026	$ 55.75	Alberta Power Pool – AESO (Flat)

The commodity contracts had a total fair value at December 31, 2025 of an asset of $12.5 million (2024 – asset of $2.1 million and liability of $687 thousand).

Subsequent to December 31, 2025, the Company entered into the following commodity contracts:

Swaps:

Product	Notional Volume	Term	Contract Price (USD/bbl)	Index
Crude Oil	100bbls/day	March 1, 2026 to March 31, 2027	$ 66.25	WTI - NYMEX
Crude Oil	100bbls/day	April 1, 2026 to March 31, 2027	$ 66.20	WTI – NYMEX
Crude Oil	100bbls/day	January 1, 2027 to June 30, 2027	$ 65.00	WTI – NYMEX
Crude Oil	1,000bbls/day	January 1, 2027 to December 31, 2027	$ 65.00 - $ 69.00	WTI – NYMEX
Crude Oil	300bbls/day	April 1, 2027 to December 31, 2027	$ 67.00 - $ 68.00	WTI – NYMEX
Crude Oil	200bbls/day	January 1, 2028 to December 31, 2028	$ 65.00 - $ 66.00	WTI – NYMEX

Product	Notional Volume	Term	Contract Price (CAD/bbl)	Index
Crude Oil	200bbls/day	March 1, 2026 to May 31, 2026	$ 105.00 - $ 127.00	WTI - NYMEX
Crude Oil	100bbls/day	March 9, 2026 to December 31, 2026	$ 110.00	WTI - NYMEX
Crude Oil	100bbls/day	April 1, 2026 to December 31, 2026	$ 99.00	WTI – NYMEX

Product	Notional Volume	Term	Contract Price (CAD/bbl)	Index
MSW Differential	500bbls/day	April 1, 2026 to December 31, 2026	$ 4.75	TMX-1A-SW

	Three months ended December 31,		**Year ended December 31,**	
	2025	2024	**2025**	2024
	$	$	**$**	$
Realized gain on commodity contracts	**3,073**	1,077	**7,810**	2,409
Unrealized gain (loss) on commodity contracts	**(3,700)**	(7,583)	**11,106**	(4,477)

The higher realized gains for the three months and year ended December 31, 2025 are driven by a decrease in benchmark commodity prices.

General and Administrative (G&A)

	Three months ended December 31, 2025	2024	Year ended December 31, 2025	2024
	$	$	**$**	$
Gross G&A	**2,262**	1,970	**8,694**	8,357
Capitalized G&A	**(350)**	(420)	**(1,340)**	(1,590)
G&A	**1,912**	1,550	**7,354**	6,767
G&A/boe	**4.12**	2.82	**3.80**	3.20

Overall G&A expenses increased during the three months ended December 31, 2025, compared to the respective period in 2024, mainly due to inflation, increased professional fees, as well as lower capitalized G&A expenses allocated during the period.

Overall G&A expenses increased during the year ended December 31, 2025, compared to the respective period in 2024, mainly due to inflation, increased staff and staffing costs, as well as a reduction of expense recoveries.

The Company continues to focus on reducing G&A costs wherever possible.

Share-based Compensation

	Three months ended December 31, 2025	2024	Year ended December 31, 2025	2024
	$	$	**$**	$
Share-based compensation	**555**	605	**2,325**	1,987

The decrease in share-based compensation during the three months ended December 31, 2025 from the comparative period of 2024 is mainly due to a reduction of expenses relating to prior grants, as well as a higher proportion of capitalized costs during the period, thereby reducing the overall expense.

The increase in share-based compensation during the year ended December 31, 2025 from the comparative periods of 2024 is mainly due to the granting of options, Restricted Share Units (“RSU’s”), Performance Share Units (“PSU’s”) and Deferred Share Units (“DSU’s”) in April 2024, October 2024, November 2024, March 2025, and November 2025.

Depletion and Depreciation (“D&D”)

	Three months ended December 31, 2025	2024	Year ended December 31, 2025	2024
	$	$	**$**	$
D&D	**5,669**	6,896	**24,331**	25,923
Per boe	**12.23**	12.56	**12.59**	12.25

The decrease in D&D for the three months and year ended December 31, 2025, as compared to the prior periods, is primarily due to lower average production levels during the current periods, along with a slight increase to the Company’s reserves base.

Impairment

As at December 31, 2025, the Company assessed its CGUs to determine whether indicators of impairment were present. The assessment identified indicators of impairment due to a weaker near-term commodity price environment and the fact that the carrying amount of the Company’s net assets at December 31, 2025 were greater than its market capitalization. As a result, impairment tests were performed on the Company’s CGUs which did not result in an impairment loss. The Company has no CGUs with historical impairment that have not been fully reversed.

No indicators of impairment were identified as at December 31, 2024, and therefore no impairment test was performed.

Finance Expenses

	Three months ended December 31, 2025	Three months ended December 31, 2024	Year ended December 31, 2025	Year ended December 31, 2024
	$	$	**$**	$
Interest on bank debt	**1,924**	2,011	**7,482**	8,524
Interest on promissory note	**-**	210	**-**	1,576
Interest income	**(15)**	(17)	**(73)**	(90)
Cash finance expenses	**1,909**	2,204	**7,409**	10,010
Accretion of decommissioning liabilities	**254**	238	**999**	920
Amortization of debt issue costs	**197**	298	**1,044**	883
Other expense	**7**	15	**39**	76
Non-cash finance expense	**458**	551	**2,082**	1,879
Total finance expenses	**2,367**	2,755	**9,491**	11,889

Interest on bank debt relates to interest and fees on Highwood's credit facility to service the bank debt. Interest on bank debt decreased for the three months and year ended December 31, 2025, as compared to the same periods last year, mainly due to lower average interest rates charged on bank balances. Overall cash finance expense decreased for the three months and year ended December 31, 2025 compared to the same periods last year due to extinguishing the Promissory Note in late 2024.

Accretion for decommissioning liabilities for the three months and year ended December 31, 2025 increased compared to the same periods in 2024. This increase is mainly due to an increase in the net decommissioning liability related to the Company's drilling and acquisitions in the current periods.

Interest rates for the bank debt are based on the Company's most recent quarter consolidated total debt to EBITDA ratio (as defined in the credit facility agreement).

Deferred Tax Expense

For the three months and year ended December 31, 2025, deferred tax was an expense of $1.9 million and $8.7 million, respectively, compared to an expense of $740 thousand and $8.6 million for the same periods last year. The expense during the periods is mainly due to the utilization of tax pools, including non-capital losses, to offset taxable income.

Income and comprehensive income

For the three months and year ended December 31, 2025, the Company realized income and comprehensive income of $5.7 million and $21.7 million, respectively, compared to income and comprehensive income of $1.9 million and $28.0 million for the same periods last year.

The decrease in income and comprehensive income for the three months and year ended December 31, 2025, compared to the same periods in 2024, was driven primarily by a decrease in overall production and lower average realized commodity pricing.

	Three months ended December 31, 2025	Three months ended December 31, 2024	Year ended December 31, 2025	Year ended December 31, 2024
	$	$	**$**	$
Income and comprehensive income	**5,719**	1,914	**21,707**	27,950
Per weighted average share, basic	**0.40**	0.13	**1.50**	1.88
Per weighted average share, diluted	**0.39**	0.13	**1.46**	1.85

Selected Annual Information

Years ended December 31,	2025	2024	2023
Financial	$	$	$
Oil and natural gas sales	98,169	135,794	41,212
Royalties	(20,623)	(29,815)	(10,520)
Transportation pipeline revenues	2,172	2,670	2,867
Processing and other income	3,219	2,917	1,734
Realized gain (loss) on commodity contracts	7,810	2,409	(118)
Unrealized gain (loss) on commodity contracts	11,106	(4,477)	5,863
Total revenue, net of royalties and commodity contracts	101,853	109,498	41,038
Cash flows from operating activities	56,397	65,777	16,376
Income	21,707	27,950	46,144
Per share, basic	1.50	1.88	4.75
Per share, diluted	1.46	1.85	4.67
Total assets	322,034	292,126	257,079
Total non-current financial liabilities (1)	105,299	91,176	83,795

(1) Excludes non-current decommissioning liabilities.

Production			
Crude Oil (bbls/d)	2,773	3,580	978
NGL (boe/d)	853	752	210
Natural Gas (mcf/d)	10,020	8,695	2,969
Oil Equivalent (boe/d)	5,296	5,781	1,682
Oil Equivalent (boe)	1,933,187	2,115,689	614,043

Selected Quarterly Information

Three months ended	Dec. 31, 2025	Sep. 30, 2025	Jun. 30, 2025	Mar. 31, 2025	Dec. 31, 2024	Sep. 30, 2024	Jun. 30, 2024	Mar. 31, 2024
Financial ($000s, except per share amounts and share numbers)								
Petroleum and natural gas sales	21,463	23,753	24,973	27,980	33,775	34,201	38,729	29,089
Transportation pipeline revenues	534	462	577	599	621	662	698	689
Income (loss)	5,719	248	13,385	2,355	1,914	16,105	10,475	(544)
Capital expenditures *(net)*	9,931	7,459	9,016	33,172	10,999	20,748	9,047	25,657
Total assets *(end of quarter)*	322,034	321,658	324,573	318,106	292,126	296,271	269,706	272,357
Working capital deficit[1] *(end of quarter)*	(11,424)	(7,730)	(22,317)	(27,151)	(7,113)	(26,531)	(23,746)	(28,791)
Shareholders' equity *(end of quarter)*	154,063	148,206	147,906	134,436	132,087	130,285	114,004	103,436
Weighted-average basic shares outstanding *(000s)*	14,263	14,390	14,564	14,616	14,754	14,801	14,907	14,937
Operations								
Production								
Crude oil *(bbls/d)*	2,623	2,787	2,861	2,824	3,638	3,607	3,947	3,126
NGL *(boe/d)*	759	841	915	899	775	701	946	586
Natural Gas *(mcf/d)*	9,943	9,749	11,134	9,250	9,319	8,194	9,398	7,869
Total *(boe/d)*	5,040	5,253	5,632	5,264	5,966	5,673	6,459	5,023
Average realized prices *($)*								
Crude oil *(per bbl)*	72.71	82.52	79.58	91.84	91.63	94.91	98.22	89.56
NGL *(per boe))*	26.88	27.07	28.26	33.45	29.51	33.48	28.61	37.79
Natural Gas *(per mcf)*	2.23	0.56	1.87	2.32	1.17	0.73	1.16	2.23

1) Working capital surplus/deficit excludes commodity contract asset/liability, current portion of decommissioning liability and current portion of lease liabilities.

Inherent to the nature of the energy industry, fluctuations in Highwood's quarterly petroleum and natural gas sales, transportation pipeline revenues, and income or loss are primarily caused by variations in production volumes, realized commodity prices and the related impact on royalties, realized and unrealized gains/losses on financial instruments, changes in per-unit expenses, and deferred income taxes. Please refer to the Operating Results and Select Consolidated Financial Disclosures sections above for an explanation of changes.

Capital Activity

	Three months ended December 31, 2025	2024	Year ended December 31, 2025	2024
	$	$	**$**	$
Land and leases	**-**	272	**4,204**	8,094
Seismic and other pre-drilling costs	**3**	1,328	**1,102**	1,992
Production equipment and facilities	**1,286**	1,105	**6,383**	6,600
Drilling and completions	**8,642**	8,391	**48,886**	49,128
Other	**-**	(97)	**57**	608
Corporate	**-**	-	**-**	29
	9,931	10,999	**60,632**	66,451

At December 31, 2025, the Company had E&E assets of $11.5 million (December 31, 2024 – $8.0 million). This amount is mainly related to undeveloped upstream oil and gas lands and exploration activities where technical feasibility has not yet been determined, along with renewal of lithium leases in the first quarter of 2025.

At December 31, 2025, the Company had gross property and equipment of $319.8 million (December 31, 2024 - $263.0 million). This included developed land and costs associated with the wells the Company has drilled and acquired to date. The Company incurred capital expenditures of $60.6 million (2024 - $66.5 million) during the year ended December 31, 2025, mainly related to drilling and completions activities.

PART 5 – CAPITALIZATION

Share Capital and Share Based Compensation Activity

As at December 31, 2025, the Company had 15,171,169 common shares, including shares held in trust, 3,150,000 warrants, 657,967 options, 337,962 RSUs, 90,000 DSUs outstanding and 985,595 common shares held in trust related to the PSU plan.

As at the date of this MD&A, the Company had 15,172,636 common shares, including shares held in trust, 3,150,000 warrants, 943,207 options, 441,895 RSUs, 112,400 DSUs outstanding and 1,090,828 common shares held in trust related to the PSU plan. Changes in these amounts since December 31, 2025 are due to the RSU exercise and grants listed below.

During the year ended December 31, 2025, the Company granted 280,411 options at an exercise price of $6.14 per option. The options granted vest 1/3 on each of the annual anniversary dates and have a five-year term.

On August 27, 2025, 37,100 stock options expired with a weighted average exercise price of $16.50 per stock option.

During the year ended December 31, 2025, the Company granted 140,805 RSUs. The RSUs granted vest 1/3 on each of the annual anniversary dates. In addition, during the year ended December 31, 2025, 18,356 RSUs were exercised resulting in 18,356 common shares being issued. During the year ended December 31, 2025, share capital was increased by the fair value of the RSU's on the day they were exercised, at a weighted average price of $5.40 per common share, for a total of $102 thousand.

Subsequent to December 31, 2025, 1,467 RSUs were exercised resulting in 1,467 common shares being issued.

During the year ended December 31, 2025, the Company granted $2.0 million worth of PSUs. The PSUs have a performance date three years from date of grant.

During the year ended December 31, 2025, the Company granted 40,000 DSUs. The DSUs granted vest one year from the grant date.

Subsequent to December 31, 2025, the Company granted 105,400 RSU's, 213,940 Options, $880,350 worth of PSU's and 22,400 DSU's. The exercise price of the Options will be the market closing price on March 17, 2026.

Liquidity, Capital Resources and Capital Management

Capital Management

Net Debt

The Company considers net debt a key capital management measure in assessing the Company's liquidity. The following table outlines the Company's calculation of net debt:

	December 31, 2025	December 31, 2024
Adjusted current assets[1]	**$ 24,491**	$ 31,928
Adjusted current liabilities[1]	**(35,915)**	(39,041)
Adjusted working capital	**(11,424)**	(7,113)
Bank debt	**(105,299)**	(90,719)
Total net debt	**$ (116,723)**	$ (97,832)

Note 1: Adjusted current assets and current liabilities excludes commodity contracts, current portion of lease liabilities and current portion of decommissioning obligations.

The increase in net debt during the year ended December 31, 2025 is mainly due to the capital expenditures incurred in the current year.

EBITDA and Adjusted EBITDA

The Company considers EBITDA and adjusted EBITDA to be a key capital management measure as it demonstrates the Company's profitability, operating and financial performance with respect to cash flow generation, adjusted for interest related to its capital structure. EBITDA is calculated by adjusting cash flows from operating activities for changes in non-cash working changes, interest and decommissioning expenditures. Adjusted EBITDA is calculated by adjusting cash flows from operating activities for changes in non-cash working changes and interest.

Adjusted funds flow

The Company considers adjusted funds flow to be a key capital management measure as it demonstrates the Company's ability to generate required funds to manage production levels and fund future capital investment. Management believes that this measure provides an insightful assessment of the Company's operations on a continuing basis by removing certain non-cash charges, decommissioning expenditures, of which the nature and timing of expenditures may vary based on the stage of the Company's assets and operating areas, and transaction costs which vary based on the Company's acquisition and disposition activity. The Company calculates adjusted funds flow as adjusted EBITDA less net interest and adjusting for decommissioning expenditures incurred.

Free funds flow

The Company considers free funds flow to be a key capital management measure as it is used to measure liquidity and efficiency of the Company by measuring the funds available after capital investment available for debt repayment, to pursue acquisitions and shareholder distributions. The Company calculates free funds flow as adjusted funds flow less expenditures on property, plant and equipment and exploration and evaluation assets (collectively, the "capital expenditures").

The following table outlines the Company's calculation of adjusted EBITDA, adjusted funds flow and free funds flow to cash flow from operating activities:

	Three months ended December 31,		Year ended December 31,	
	2025	2024	**2025**	2024
Cash flow from operating activities	**$ 16,812**	$ 18,368	**$ 56,397**	$ 65,777
Change in non-cash operating working capital	**(7,839)**	(1,577)	**(10,520)**	3,357
Net interest[1]	**1,910**	2,204	**7,409**	10,010
Adjusted EBITDA	**10,883**	18,995	**53,286**	79,144
Decommissioning expenditures	**1,628**	1,370	**2,054**	1,616
EBITDA	**12,511**	20,365	**55,340**	80,760
Net interest[1]	**(1,910)**	(2,204)	**(7,409)**	(10,010)
Adjusted funds flow	**10,601**	18,161	**47,931**	70,750
Net capital expenditures, net	**(9,931)**	(10,999)	**(59,578)**	(66,451)
Free funds flow	**$ 670**	$ 7,162	**$ (11,647)**	$ 4,299

Note 1: Net interest is interest on bank debt and promissory note less interest income

The decrease in EBITDA, Adjusted EBITDA, Adjusted funds flow, and free funds flow for the three months and year ended December 31, 2025, compared to the same period in 2024, is primarily due to lower production and lower commodity pricing.

The Company makes adjustments to capital employed by monitoring economic conditions and investment opportunities. The Company generally relies on credit facilities and cash flows from operations to fund capital requirements. To maintain or modify its capital structure, the Company may issue new common or preferred shares, issue new subordinated debt, renegotiate existing debt terms, or repay existing debt. The Company is not currently subject to any externally imposed capital requirements, other than covenants on its Amended and Restated Credit Agreement (the "ARCA").

Liquidity and Capital Resources

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with its financial liabilities as they become due. The Company's financial liabilities, excluding commodity contracts consist of accounts payable and accrued liabilities and bank debt.

The Company has an ARCA which is comprised of senior secured extendible revolving credit facilities in the aggregate principal amount of up to $140 million with a syndicate of banks. The ARCA is comprised of revolving credit facilities consisting of a $10 million operating facility and a syndicated loan facility to a maximum of $130 million. The ARCA allows the Company to enter into Letters of Credit up to a maximum of $20 million. During the second quarter of 2025, the term out date was amended from August 2, 2025 to August 2, 2026 as well as an increase to the syndicated loan facility from a maximum of $110 million.

At December 31, 2025, the Company had a working capital deficit of $11.4 million, excluding commodity contract asset, current portion of decommissioning liability, and current portion of lease liabilities. The capital-intensive nature of the Company's operations may create a working capital deficiency position during periods with high levels of capital investment. The working capital deficit at December 31, 2025, was mainly driven by the capital program incurred during the fourth quarter. The Company expects to repay its financial liabilities in the normal course of operations and to fund future operational and capital requirements through operating cash flows and available capacity on the Company's ARCA. The maturity date of the bank debt is August 2, 2027; therefore, all bank debt has been classified as long-term.

The Company monitors liquidity risk through cost control, debt and equity management policies. Strategies include continuously monitoring of forecast and actual cash flows, financing activities and available credit available under the ARCA. The nature of the oil and gas industry is very capital intensive. The Company prepares annual capital expenditure budgets and utilizes authorizations for expenditures and capital committees for projects to manage capital expenditures.

The Company may need to conduct asset sales, equity issues or issue debt if liquidity risk increases in a given period. Liquidity risk may increase as a result of potential revisions to the Company's ARCA, which is subject to semi-annual reviews. The Company also maintains and monitors a certain level of cash flow which is used to partially finance all operating and capital expenditures. The Company believes it has sufficient funds and operating cash flows to meet foreseeable obligations by actively monitoring its credit facilities and coordinating payment and revenue cycles each month. However, there are no assurances that the lender will maintain the borrowing base at the current level, which may result in a borrowing base shortfall. If the Company cannot generate sufficient funds to meet the borrowing base shortfall it would constitute an event of default under the loan agreement and the bank could demand immediate repayment of the outstanding loan amount. The Company actively monitors covenants associated with the credit facilities and was in compliance at December 31, 2025.

The following table details the Company's financial liabilities, excluding commodity contracts, as at December 31, 2025:

	Total	**<1 year**	**1-3 years**
Accounts payable and accrued liabilities	**$ 35,915**	$ 35,915	$ -
Bank debt	**105,299**	-	105,299
Lease liabilities	**211**	211	-
Total financial liabilities	**$ 141,425**	$ 36,126	$ 105,299

Commitments

During the year ended December 31, 2025, the Company entered into a new lease for its existing office space. The agreement takes effect in 2026 and has a term of five years. Gross payment obligations related to the new lease, excluding occupancy costs, are approximately $600 thousand annually.

Off-Balance-Sheet Arrangements

The Company does not have any special-purpose entities nor is it a party to any arrangements that would be excluded from the statement of financial position.

Environmental Initiatives Affecting Highwood

The oil and gas industry has a number of environmental risks and hazards and is subject to regulation by all levels of government. Environmental legislation includes, but is not limited to, operational controls, site restoration requirements and restrictions on emissions of various substances produced in association with oil and natural gas operations. Compliance with such legislation could require additional expenditures and a failure to comply may result in fines and penalties which could, in the aggregate and under certain unlikely assumptions, become significant. Operations are continuously monitored to minimize the environmental impact, and capital is allocated to reclamation and other activities to mitigate the impact on the areas in which we operate.

Related-Party Transactions

(a) Key management compensation

The remuneration of the key management personnel of the Company, which includes directors and officers is set out below in aggregate:

	Years ended December 31,	
	2025	2024
Salaries, bonuses and consulting fees	**$ 1,740**	$ 2,751
Share based compensation	**2,073**	1,360
Total key management compensation	**$ 3,813**	$ 4,111

PART 6 – OTHER

Critical Accounting Judgments, Estimates and Policies

The Company's critical accounting judgements, estimates and policies are described in notes 2, 3 and 4 to the December 31, 2025 annual consolidated financial statements. Certain accounting policies are identified as critical because they require management to make judgments and estimates based on conditions and assumptions that are inherently uncertain, and because the estimates are of material magnitude to revenue, expenses, funds flow from operations, income or loss and/or other important financial results. These accounting policies could result in materially different results should the underlying conditions change or the assumptions prove incorrect.

Non-GAAP and Specified Financial Measures

This MD&A includes references to financial measures commonly used in the oil and natural gas industry. The term "operating netback" (oil and natural gas sales less royalties and production, operating and transportation expenses, all expressed on a per-unit-of-production basis) is not defined under IFRS, and may not be comparable with similar measures presented by other companies. Operating netback is a per-unit-of-production measure that may be used to assess the Company's performance and efficiency.

The term "working capital surplus (deficit), excluding bank debt" is not defined under IFRS, and may not be comparable with similar measures presented by other companies. Working capital surplus (deficit), excluding bank debt is included to show what the working capital relating to customers, vendors, and joint venture partners would be.

The term "funds flow from operations" is not defined under IFRS and may not be comparable with similar measures presented by other companies. Funds flow from operations is included to show what the cash flow from operating activities would be prior to changes in working capital and changes in long-term accounts payable and accrued liabilities.

The term "Net Debt" is not defined under IFRS and may not be comparable with similar measures presented by other companies. represents the carrying value of the Company's debt instruments, including outstanding deferred acquisition payments, net of Adjusted working capital. The Company uses Net Debt as an alternative to total outstanding debt as Management believes it provides a more accurate measure in assessing the liquidity of the Company. The Company believes that Net Debt can provide useful information to investors and shareholders in understanding the overall liquidity of the Company.

The term "EBITDA" is not defined under IFRS and may not be comparable with similar measures presented by other companies. EBITDA is used as an alternative measure of profitability and attempts to represent the cash profit generated by the Company's operations. The most directly comparable GAAP measure is cash flow from (used in) operating activities. EBITDA is calculated as cash flow from (used in) operating activities, adding back changes in non-cash working capital, decommissioning obligation expenditures and interest expense.

“Adjusted EBITDA” is calculated as cash flow from (used in) operating activities, adding back changes in non-cash working capital, transaction costs and interest expense. The Company considers Adjusted EBITDA to be a key capital management measure as it is both used within certain financial covenants anticipated to be prescribed under the ARCA and demonstrates Highwood’s standalone profitability, operating and financial performance in terms of cash flow generation, adjusting for interest related to its capital structure. The most directly comparable GAAP measure is cash flow from (used in) operating activities.

“Free Cash Flow” or “FCF” is used as an indicator of the efficiency and liquidity of the Company’s business, measuring its funds after capital expenditures available to manage debt levels, pursue acquisitions and assess the optionality to pay dividends and/or return capital to shareholders though activities such as share repurchases. The most directly comparable GAAP measure is cash flow from (used in) operating activities. Free Cash Flow is calculated as cash flow from (used in) operating activities, less interest, office lease expenses, cash taxes and capital expenditures.

“Net Debt” represents the carrying value of the Company’s debt instruments, including outstanding deferred acquisition payments, net of Adjusted working capital. The Company uses Net Debt as an alternative to total outstanding debt as Management believes it provides a more accurate measure in assessing the liquidity of the Company. The Company believes that Net Debt can provide useful information to investors and shareholders in understanding the overall liquidity of the Company.

"Net Debt / EBITDA" is calculated as net debt at the ending period of each financial quarter divided by the EBITDA for that period. The Company believes that Net Debt / EBITDA is useful information to investors and shareholders in understanding the time frame, in years, it would take to eliminate Net Debt based on current period Exit EBITDA.

"2025 Exit EBITDA" is calculated as Adjusted EBITDA for the month of December annualized. The Company believes that 2025 Exit EBITDA is useful information to investors and shareholders in understanding the EBITDA generated in the final month of 2025,which is indicative of future EBITDA.

"Net Debt / 2025 Exit EBITDA" is calculated as net debt at the end of the fiscal period of 2025 divided by the 2025 Exit EBITDA. The Company believes that Net Debt / 2025 Exit EBITDA is useful information to investors and shareholders in understanding the time frame, in years, it would take to eliminate Net Debt based on 2025 Exit EBITDA.

“Operating netback (per BOE)” is calculated as the realized price per boe, less royalties associated with the sale of petroleum and natural gas products on a per boe basis, less the operating costs associated with the production on a per boe basis. The Company believes that Operating netback (per BOE) is a useful measure of the profit that is made from each barrel of production.

Basis of Barrel of Oil Equivalent

Petroleum and natural gas reserves and production volumes are stated as a “barrel of oil equivalent” (boe), derived by converting natural gas to oil equivalency in the ratio of 6,000 cubic feet of gas to one barrel of oil. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6,000 cubic feet of gas to one barrel of oil is based on energy equivalency, which is primarily applicable at the burner tip, and does not represent a value equivalency at the wellhead. Readers are cautioned that boe figures may be misleading, particularly if used in isolation. This conversion conforms to the Canadian Securities Regulator’s National Instrument 51-101 – Standards for Oil and Gas Activities.

Caution Respecting Reserves Information

Readers should see the "Selected Technical Terms" in the Annual Information Form filed on March 16, 2026 for the definition of certain oil and gas terms.

Disclosure of oil and gas information is presented in accordance with generally accepted industry practices in Canada and National Instrument 51-101— Standards of Disclosure for Oil and Gas Activities ("**NI 51-101**"). Other than as noted herein, the oil and gas information regarding the Company presented in this news release is based on the reserves report prepared by GLJ Ltd. evaluating the crude oil, natural gas and natural gas liquids attributable to the Company's properties at January 1, 2026 (the "**2025 Reserves Report**").

Reserves are classified according to the degree of certainty associated with the estimates as follows:

"BT" means before tax.

"IRR" means internal rate of recovery.

"RLI" means reserves life index and is calculated as total company interest reserves divided by annual production, as per the 2025 Reserves Report.

"NPV10" represents the anticipated net present value of the future net revenue discounted at a rate of 10% associated with the reserves associated with the acquired assets.

"F&D" is calculated as the sum of field capital plus the change in FDC for the period divided by the change in reserves that are characterized as development for the period is calculated as the sum of field capital plus the change in FDC for the period divided by the change in total reserves, other than from production, for the period. Finding and development costs take into account reserves revisions during the year on a per boe basis. The aggregate of the exploration and development costs incurred in the financial year and changes during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year. Management uses F&D costs as a measure of capital efficiency for organic reserves development.

"NAV per share" is calculated using the respective net present values of PDP, 1P and 2P reserves, before tax and discounted at 10% plus internally valued undeveloped land & seismic, less net debt, and divided by basic outstanding common shares adjusted for shares held in treasury. Management used NAV per share as a measure of the relative change of Highwood's net asset value over its outstanding common shares over a period of time.

"NAV per fully diluted share" is calculated using the respective net present values of PDP, 1P and 2P reserves, before tax and discounted at 10% plus internally valued undeveloped land & seismic and proceeds from warrants and stock options, less net debt, and divided by fully diluted outstanding shares. Management used NAV per share as a measure of the relative change of Highwood's net asset value over its outstanding common shares over a period of time.

"Netback" is used to evaluate potential operating performance. Netback is calculated as follows: (Revenue – Royalties - Operating Expenses).

"Recycle Ratio" is measured by dividing the operating netback for the applicable period by F&D cost per boe for the year. The recycle ratio compares netback from existing reserves to the cost of finding new reserves and may not accurately indicate the investment success unless the replacement reserves are of equivalent quality as the produced reserves.

"Proved Developed Producing" or "PDP" reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

"Proved" or "1P" reserves are those that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Reported reserves should target at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves under a specific set of economic conditions.

"Proved plus Probable" or "2P" reserves are those that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved plus probable reserves. Reported reserves should target at least a 50 percent probability that the probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves under a specific set of economic conditions.

"Drilling Location" or "Locations" – this news release discloses drilling inventory in two categories: (a) booked locations; and (b) unbooked locations. Booked locations are proposed drilling locations identified in the Year-End 2025 Reserves, as evaluated by GLJ who is the Company's independent qualified reserves evaluator, that have proved and/or probable reserves, as applicable, attributed to them in the Year-End 2025 Reserves. Unbooked locations are internal estimates based on prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal technical analysis review. Unbooked locations have been identified by members of management. Unbooked locations do not have proved or probable reserves attributed to them in the Year-End 2025 Reserves. 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 natural gas reserves, resources or production. The drilling locations considered for future development will ultimately depend on 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. While certain of unbooked drilling locations have been de-risked by the drilling of existing wells by Highwood in relatively close proximity to such unbooked drilling locations, other unbooked drilling locations are farther away from existing wells where Management has less information about the characteristics of the reservoir, and therefore, there is more uncertainty whether wells will be drilled in such locations. If these wells are drilled, there is more uncertainty that such wells will result in additional oil and natural gas reserves, resources or production.

Forward-Looking Statements

This document contains certain forward-looking statements. Forward-looking statements are subject to known and unknown risks, uncertainties and other factors that could influence actual results or events and cause them to differ materially from those stated, anticipated or implied. Such forward-looking statements necessarily involve risks including, without limitation, those associated with oil and natural gas exploration, property development, production, marketing and transportation, such as dry holes and non-commercial wells, facility and pipeline damage, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, production declines, health, safety and environmental risks, competition from other producers and the ability to access sufficient capital from internal and external sources. Forward-looking information typically includes statements with words such as “anticipate”, “believe”, “expect”, “plan”, “intend”, “estimate”, “propose”, “project”, or similar words suggesting future outcomes. The Company cautions readers and prospective investors in the Company’s securities not to place undue reliance on forward-looking information as, by its nature, it is based on current expectations regarding future events that involve a number of assumptions, inherent risks and uncertainties, which could cause actual results to differ materially from those anticipated by the Company.

Forward-looking information typically involves substantial known and unknown risks and uncertainties, certain of which are beyond the Company’s control. Such risks and uncertainties include, without limitation: financial risk of marketing reserves or metals & minerals at an acceptable price given market conditions; volatility in market prices for metals, minerals, oil and natural gas; delays in business operations; pipeline restrictions; blowouts; the risk of carrying out operations with minimal environmental impact; industry conditions including changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; uncertainties associated with estimating mining resources & oil and natural gas reserves; risks and uncertainties related to mining and oil & gas interests and operations on aboriginal lands; economic risk of finding and producing reserves at a reasonable cost; uncertainties associated with partner plans and approvals; operational matters related to non-operated properties; increased competition for, among other things, capital, acquisitions of mining permits, reserves and undeveloped lands; competition for and availability of qualified personnel or management; incorrect assessments of the value of acquisitions and exploration and development programs; unexpected geological, technical, drilling, construction, processing and transportation problems; availability of insurance; fluctuations in foreign exchange and interest rates; stock market volatility; general economic, market and business conditions; uncertainties associated with regulatory approvals; uncertainty of government policy changes; uncertainties associated with credit facilities and counterparty credit risk; changes in income tax laws, Crown royalty rates and incentive programs relating to the oil and gas industry; and other factors, many of which are outside the Company's control. The Company's actual results, performance or achievements could, therefore, differ materially from those expressed in, or implied by, these forward-looking estimates and whether or not any such actual results, performance or achievements transpire or occur, there can be no certainty as to what benefits or detriments the Company will derive therefrom.

The forward-looking information included herein is expressly qualified in its entirety by this cautionary statement. It is made as of the date hereof and the Company assumes no obligation to update or revise any forward-looking information to reflect new events or circumstances, except as required by law.

Abbreviations

The following summarizes the abbreviations used in this document:

Crude Oil and Natural Gas Liquids

bbl	barrel
Mbbl	thousand barrels
bbls/d	barrels per day
boe	barrel of oil equivalent
Mboe	thousand barrels of oil equivalent
boe/d	barrel of oil equivalent per day
NGL	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
GJ	Gigajoule; 1 Mcf of natural gas is about 1.05 GJ
MMBtu	million British thermal units; 1 GJ is about 0.95 MMBtu

Other

$000s	thousands of dollars
IFRS	IFRS Accounting Standards as issued by the IASB
IASB	International Accounting Standards Board

Corporate Information

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Tomahawk, Wisconsin

RYAN MOONEY
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GREG MACDONALD
President & Chief Executive Officer

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