Management’s Discussion and Analysis

Q3 2025

ATHABASCA OIL CORPORATION

This Management’s Discussion and Analysis of the financial condition and results of operations (“MD&A”) of Athabasca Oil Corporation (“Athabasca”, the “Company” or the "Parent Company") is dated October 29, 2025 and should be read in conjunction with the unaudited condensed interim consolidated financial statements ("Consolidated Financial Statements") as at and for the three and nine months ended September 30, 2025 and the MD&A and audited consolidated financial statements of the Company for the year ended December 31, 2024. These financial statements, including the comparative figures, were prepared in accordance with International Financial Reporting Standards (“IFRS”). This MD&A contains forward looking information based on the Company’s current expectations and projections. For information on the material factors and assumptions underlying such forward-looking information, refer to the “Advisories and Other Guidance” section within this MD&A. Also see the "Advisories and Other Guidance" section within this MD&A for important information regarding the Company's reserves and resource information and abbreviations included in this MD&A. Additional information relating to Athabasca is available on SEDAR at www.sedarplus.ca, including the Company’s most recent Annual Information Form dated March 5, 2025 (“AIF”). The Company’s common shares are listed on the Toronto Stock Exchange under the trading symbol “ATH”.

FOCUSED | EXECUTING | DELIVERING

ATHABASCA'S STRATEGY

Athabasca is a liquids-weighted intermediate producer with exposure to Canada's premier resource plays (Oil Sands, Duvernay). The Company's strategy is guided by:

- Thermal Oil: Predictable, Low Decline Production with Compelling Growth Projects
- Duvernay Energy Corporation ("Duvernay Energy"): Self-funded, Liquids Rich Development
- Financial Sustainability: Low Leverage, Flexible Capital, Prudent Risk Management

Athabasca's strategy is focused on maximizing cash flow per share growth through investing in high margin projects and executing on return of capital initiatives. The Company has long term growth optionality across a deep inventory of high-quality Thermal Oil projects and flexible Duvernay development opportunities. This balanced portfolio provides shareholders with differentiated exposure to liquids weighted production and significant long reserve life assets.

THIRD QUARTER 2025 HIGHLIGHTS

Corporate Consolidated(1)

- Production of 39,599 boe/d (98% Liquids(2)), representing a 2% growth from the third quarter of 2024 (11% on a basic per share basis).
- Petroleum, natural gas and midstream sales of $333.4 million.
- Operating Income(2) and Operating Netback(2) of $151.8 million ($42.50/boe).
- Adjusted Funds Flow(2) of $129.2 million and $0.26 per basic share (cash flow from operating activities of $157.4 million).
- Strong Liquidity(2) of $466.0 million, including $334.6 million of cash as at September 30, 2025.
- Repurchased a total of 31.6 million common shares for $174.1 million year to date, supported by strong Free Cash Flow generation in Thermal Oil.

Athabasca (Thermal Oil)

- Production of 36,590 bbl/d including 27,763 bbl/d at Leismer and 8,827 bbl/d at Hangingstone.
- Petroleum, natural gas and midstream sales of $329.5 million.
- Operating Income(2) and Operating Netback(2) of $142.6 million ($43.28/bbl).
- Adjusted Funds Flow(2) of $121.1 million; Free Cash Flow(2) of $56.2 million.
- Year to date capital expenditures of $171.5 million. At Leismer, the Company advanced its expansion project and field activity included facilities, pipeline construction on Pad 10 and 11, commencing steaming on Pad 10 (first two wells on production in July), drilling five observation wells and the completion of six redrills on Pad 1 with first production in March. At Hangingstone, the Company completed the conversion and steaming of two well pairs on Pad AA with first production in March.

Duvernay Energy(1)

- Production of 3,009 boe/d (75% Liquids(2)).
- Petroleum, natural gas and midstream sales of $15.8 million.
- Operating Income(2) and Operating Netback(2) of $9.2 million ($33.25/boe).
- Adjusted Funds Flow(2) of $8.1 million.
- Year to date capital expenditures of $61.1 million. Activity included drilling and completing a four well pad (30% working interest), which was placed on production in the third quarter; and completion activities on a three well pad (100% working interest), which is expected to be placed on production in the fourth quarter of 2025. Capital expenditures last winter also included the construction of a pipeline connecting the Duvernay Energy south lands to the Kaybob East Facility and construction of regional water infrastructure to support future development plans.

(1) Corporate Consolidated and Duvernay Energy reflect gross production and financial metrics before taking into consideration Athabasca's 70% equity interest in Duvernay Energy.
(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures and production disclosure.

FINANCIAL & OPERATIONAL HIGHLIGHTS

The following tables summarize selected financial and operational information of the Company for the periods indicated:

($ Thousands, unless otherwise noted)	Three months ended September 30, 2025	2024	Nine months ended September 30, 2025	2024
CORPORATE CONSOLIDATED[1]				
Petroleum and natural gas production (boe/d)[2]	39,599	38,909	38,807	36,675
Petroleum, natural gas and midstream sales	$ 333,397	$ 376,781	$ 1,061,311	$ 1,089,635
Operating Income[2]	$ 151,835	$ 180,184	$ 439,132	$ 465,070
Operating Income Net of Realized Hedging[2][3]	$ 144,650	$ 175,755	$ 430,698	$ 460,511
Operating Netback ($/boe)[2]	$ 42.50	$ 49.12	$ 41.71	$ 46.36
Operating Netback Net of Realized Hedging ($/boe)[2][3]	$ 40.49	$ 47.91	$ 40.91	$ 45.91
Capital expenditures	$ 96,190	$ 50,634	$ 232,589	$ 175,098
Cash flow from operating activities	$ 157,414	$ 187,143	$ 382,199	$ 398,864
per share - basic	$ 0.32	$ 0.35	$ 0.76	$ 0.72
Adjusted Funds Flow[2]	$ 129,197	$ 163,680	$ 386,463	$ 417,198
per share - basic	$ 0.26	$ 0.30	$ 0.77	$ 0.75
ATHABASCA (THERMAL OIL)				
Bitumen production (bbl/d)[2]	36,590	34,853	35,942	33,390
Petroleum, natural gas and midstream sales	$ 329,542	$ 372,634	$ 1,047,077	$ 1,072,954
Operating Income[2]	$ 142,631	$ 163,694	$ 413,750	$ 425,837
Operating Netback ($/bbl)[2]	$ 43.28	$ 49.68	$ 42.46	$ 46.64
Capital expenditures	$ 64,965	$ 44,431	$ 171,451	$ 120,634
Adjusted Funds Flow[2]	$ 121,131	$ 150,088	$ 364,581	$ 383,214
Free Cash Flow[2]	$ 56,166	$ 105,657	$ 193,130	$ 262,580
DUVERNAY ENERGY[1]				
Petroleum and natural gas production (boe/d)[2]	3,009	4,056	2,865	3,285
Percentage Liquids (%)[2]	75%	77%	73%	77%
Petroleum, natural gas and midstream sales	$ 15,840	$ 24,728	$ 46,985	$ 63,015
Operating Income[2]	$ 9,204	$ 16,490	$ 25,382	$ 39,233
Operating Netback ($/boe)[2]	$ 33.25	$ 44.20	$ 32.45	$ 43.59
Capital expenditures	$ 31,225	$ 6,203	$ 61,138	$ 54,464
Adjusted Funds Flow[2]	$ 8,066	$ 13,592	$ 21,882	$ 33,984
Free Cash Flow[2]	$ (23,159)	$ 7,389	$ (39,256)	$ (20,480)
NET INCOME AND COMPREHENSIVE INCOME				
Net income and comprehensive income[4]	$ 69,640	$ 68,722	$ 198,514	$ 203,407
per share - basic[4]	$ 0.14	$ 0.13	$ 0.39	$ 0.37
per share - diluted[4]	$ 0.14	$ 0.12	$ 0.39	$ 0.36
COMMON SHARES OUTSTANDING				
Weighted average shares outstanding - basic	494,509,594	540,884,257	503,714,495	555,035,218
Weighted average shares outstanding - diluted	497,929,426	550,712,443	507,263,981	559,203,568

As at ($ Thousands)	September 30, 2025	December 31, 2024
LIQUIDITY AND BALANCE SHEET (CONSOLIDATED)		
Cash and cash equivalents	$ 334,550	$ 344,836
Available credit facilities[5]	$ 131,408	$ 136,324
Face value of long-term debt	$ 201,666	$ 200,000

(1) Corporate Consolidated and Duvernay Energy reflect gross production and financial metrics before taking into consideration Athabasca's 70% equity interest in Duvernay Energy.
(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures and production disclosure.
(3) Includes realized commodity risk management loss of $7.2 million and $8.4 million for the three and nine months ended September 30, 2025 (three and nine months ended September 30, 2024 – loss of $4.4 million and $4.6 million).
(4) Net income and comprehensive income per share amounts are based on net income and comprehensive income attributable to shareholders of the Parent Company. In the calculation of diluted net income per share for the three months ended September 30, 2024 net income was reduced by $2.6 million, to account for the impact to net income had the outstanding warrants been converted to equity.
(5) Includes available credit under Athabasca's and Duvernay Energy's Credit Facilities and Athabasca's Unsecured Letter of Credit Facility.

BUSINESS ENVIRONMENT

Benchmark prices

(Average)	Three months ended September 30, 2025	2024	Change	Nine months ended September 30, 2025	2024	Change
Crude oil:						
West Texas Intermediate (WTI) (US$/bbl)[1]	$ 64.93	$ 75.09	(14) %	$ 66.70	$ 77.54	(14) %
West Texas Intermediate (WTI) (C$/bbl)[1]	$ 89.43	$ 102.39	(13) %	$ 93.26	$ 105.47	(12) %
Western Canadian Select (WCS) (C$/bbl)[2]	$ 75.11	$ 83.91	(10) %	$ 77.79	$ 84.41	(8) %
Edmonton Par (C$/bbl)[3]	$ 86.18	$ 97.85	(12) %	$ 88.54	$ 98.46	(10) %
Edmonton Condensate (C5+) (C$/bbl)[4]	$ 86.43	$ 96.49	(10) %	$ 91.17	$ 99.57	(8) %
WCS Differential:						
to WTI (US$/bbl)	$ (10.39)	$ (13.55)	(23) %	$ (11.11)	$ (15.49)	(28) %
to WTI (C$/bbl)	$ (14.32)	$ (18.48)	(23) %	$ (15.47)	$ (21.06)	(27) %
Edmonton Par Differential:						
to WTI (US$/bbl)	$ (2.20)	$ (3.35)	(34) %	$ (3.34)	$ (5.21)	(36) %
to WTI (C$/bbl)	$ (3.25)	$ (4.54)	(28) %	$ (4.72)	$ (7.01)	(33) %
Natural gas:						
AECO (C$/GJ)[5][6]	$ 0.60	$ 0.65	(8) %	$ 1.42	$ 1.38	3 %
Foreign exchange:						
USD : CAD	1.3774	1.3635	1 %	1.3982	1.3602	3 %

Primary benchmark for:
(1) Light Oil pricing in North America.
(2) Athabasca's Heavy oil (i.e. blended bitumen) sales.
(3) Light oil (i.e. light and medium crude oil and tight oil) sales in Duvernay Energy.
(4) Natural gas liquids condensate sales in Duvernay Energy and for diluent purchases in Thermal Oil.
(5) Natural gas consumed by Athabasca in order to generate steam in Thermal Oil.
(6) Natural gas (i.e. shale gas and conventional natural gas) sales in Duvernay Energy.

OUTLOOK

2025 Operational & Financial Guidance ($ millions, unless otherwise noted)	Athabasca (Thermal Oil)(2)	Duvernay Energy(2)(3)	Corporate Consolidated(2)(3)
Production (boe/d)(1)	~35,500	~3,500	~37,500-39,500
Adjusted Funds Flow(1)	~$475-$500	~$45	~$525-$550
Capital Expenditures(4)	~$250	~$75	~$325
Free Cash Flow(1)	~$250	—	—

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP measures and production disclosure.
(2) Commodity price assumptions: 2025 year to date actualized and US$60 WTI, US$12.50 WCS heavy differential, C$2 AECO, and 0.725 C$/US$ FX for balance of the year.
(3) Duvernay Energy reflects gross production and financial metrics before taking into consideration Athabasca's 70% equity interest in Duvernay Energy.
(4) 2025 Duvernay Energy capital expenditures are trending approximately $10 million lower than original budget of approximately $85 million.

The Company anticipates production at the upper end of its original guidance of 37,500 – 39,500 boe/d. Thermal Oil production is expected to average approximately 35,500 bbl/d and Duvernay Energy is expected to average approximately 3,500 boe/d with an exit target of 5,500 - 6,000 boe/d.

The forecast capital budget for Thermal Oil is unchanged at approximately $250 million, including sustaining capital and the Leismer expansion project. This $300 million expansion project (over three years) is highly economic (approximately $25,000/bbl/d capital efficiency) and provides flexibility with interim growth before achieving the regulatory approved 40,000 bbl/d capacity at the end of 2027. Athabasca's Thermal Oil capital projects are flexible, highly economic and have phased optionality on timing based on the macroeconomic environment. The Company anticipates being approximately 50% complete of total capital exposure for the expansion project by year-end 2025 and being substantially complete by year-end 2026. Duvernay Energy's forecast capital budget is unchanged at approximately $75 million and will drive production momentum in the fourth quarter of 2025.

The Company forecasts consolidated Adjusted Funds Flow of $525 - $550 million, including $475 - $500 million from its Thermal Oil assets. 2025 Thermal Oil Free Cash Flow is forecasted at approximately $250 million and is planned to be returned to shareholders through share buybacks. Every +US$1/bbl move in West Texas Intermediate ("WTI") and Western Canadian Select ("WCS") heavy oil impacts annual Adjusted Funds Flow by approximately $10 million and approximately $17 million, respectively.

CORPORATE CONSOLIDATED OPERATING RESULTS

For analysis of operating results see the Athabasca (Thermal Oil) and Duvernay Energy sections within this MD&A. For further details related to commodity risk management gains/losses see the Risk Management Contracts section.

	Three months ended September 30, 2025	2024	Nine months ended September 30, 2025	2024
PRODUCTION				
Bitumen (bbl/d)	36,590	34,853	35,942	33,390
Oil and condensate (bbl/d)(1)	2,053	2,688	1,834	2,235
Natural gas (Mcf/d)(1)	4,563	5,526	4,578	4,511
Other natural gas liquids (bbl/d)(1)	196	447	268	298
Total (boe/d)(1)	39,599	38,909	38,807	36,675

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP measures and production disclosure.

($ Thousands, unless otherwise noted)	Three months ended September 30, 2025	2024	Nine months ended September 30, 2025	2024
Petroleum, natural gas and midstream sales(1)	$ 345,382	$ 397,362	$ 1,094,062	$ 1,135,969
Royalties	(11,863)	(24,761)	(41,811)	(70,933)
Cost of diluent(1)	(122,011)	(129,965)	(421,208)	(411,991)
Operating expenses	(37,317)	(39,581)	(124,798)	(123,019)
Transportation and marketing(2)	(22,356)	(22,871)	(67,113)	(64,956)
Operating Income(3)	151,835	180,184	439,132	465,070
Realized loss on commodity risk mgmt. contracts	(7,185)	(4,429)	(8,434)	(4,559)
OPERATING INCOME NET OF REALIZED HEDGING(3)	$ 144,650	$ 175,755	$ 430,698	$ 460,511
REALIZED PRICES(3)				
Heavy oil (Blended bitumen) ($/bbl)(3)	$ 71.86	$ 82.62	$ 74.84	$ 83.06
Oil and condensate ($/bbl)(3)	79.87	93.29	84.81	95.70
Natural gas ($/Mcf)(3)	0.73	0.74	1.76	1.44
Other natural gas liquids ($/bbl)(3)	25.03	31.08	31.74	32.16
Realized price (net of cost of diluent) ($/boe)(3)	62.53	72.90	63.92	72.16
Royalties ($/boe)(3)	(3.32)	(6.75)	(3.97)	(7.07)
Operating expenses ($/boe)(3)	(10.45)	(10.79)	(11.86)	(12.26)
Transportation and marketing ($/boe)(2)(3)	(6.26)	(6.24)	(6.38)	(6.47)
Operating Netback ($/boe)(3)	42.50	49.12	41.71	46.36
Realized loss on commodity risk mgmt. contracts ($/boe)(3)	(2.01)	(1.21)	(0.80)	(0.45)
OPERATING NETBACK NET OF REALIZED HEDGING ($/boe)(3)	$ 40.49	$ 47.91	$ 40.91	$ 45.91

(1) Non-GAAP measure includes intercompany NGLs (i.e. condensate) sold by the Duvernay Energy segment to the Athabasca (Thermal Oil) segment for use as diluent that is eliminated on consolidation.
(2) Transportation and marketing excludes non-cash costs of $0.6 million and $1.7 million for the three and nine months ended September 30, 2025 (three and nine months ended September 30, 2024 - $0.6 million and $1.7 million).
(3) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures and production disclosure.

Corporate Consolidated Capital Expenditures

($ Thousands)	Three months ended September 30, 2025	2024	Nine months ended September 30, 2025	2024
Athabasca (Thermal Oil)	$ 64,965	$ 44,431	$ 171,451	$ 120,634
Duvernay Energy	31,225	6,203	61,138	54,464
CORPORATE CONSOLIDATED CAPITAL EXPENDITURES(1)(2)(3)	$ 96,190	$ 50,634	$ 232,589	$ 175,098

(1) For the three and nine months ended September 30, 2025, expenditures include cash capitalized stock-based compensation costs of $nil (three and nine months ended September 30, 2024 - $nil and $0.5 million).
(2) For the three and nine months ended September 30, 2025, expenditures include capitalized staff costs of $2.3 million and $7.2 million (three and nine months ended September 30, 2024 - $2.1 million and $6.1 million).
(3) Excludes non-cash capitalized costs related to stock-based compensation and decommissioning obligation assets.

ATHABASCA (THERMAL OIL)

Athabasca's Thermal Oil assets consist of its cornerstone producing Leismer asset, its producing Hangingstone asset, the high-quality Corner lease which is an extension of the Leismer field and the Dover West exploration asset in the Athabasca region of northeastern Alberta. The Thermal Oil assets underpin the Company’s low corporate production decline and low relative sustaining capital requirements, supporting free cash flow generation in the current environment.

Athabasca has a 100% working interest in the producing Leismer Thermal Oil Project (the "Leismer Project") and the delineated Corner lease. The Leismer Project was commissioned in 2010 and has a reserve life index of approximately 70 years (proved plus probable) at current production levels. The Leismer Project has Proved plus Probable Reserves of approximately 694 MMbbl(1) and Best Estimate Development Pending Contingent Resources of 421 MMbbl (risked)(1) (468 MMbbl unrisked)(1). The Corner lease has Proved plus Probable Reserves of approximately 351 MMbbl(1) and Best Estimate Development Pending Contingent Resources of 416 MMbbl (risked)(1) (520 MMbbl unrisked)(1). The Leismer and Corner development application has regulatory approval for future development phases of up to a combined 80,000 bbl/d.

Athabasca also has a 100% working interest in the producing Hangingstone Thermal Oil Project (the “Hangingstone Project"). The Hangingstone Project was commissioned in 2015 and has a reserve life index of approximately 50 years (proved plus probable) at current production levels. Hangingstone has Proved plus Probable Reserves of approximately 163 MMbbl(1).

<u>Royalty</u>

Athabasca has granted Contingent Bitumen Royalties on its Thermal Oil assets. The royalty structure ensures the Thermal Oil assets are not encumbered at low commodity prices while allowing strong participation at high commodity prices. The Royalty on the Leismer and Hangingstone projects are based on a scale from 0% – 15% with a Western Canadian Select (“WCS”) heavy benchmark. At prices below US$60 WCS the rate is 0%. The minimum 2.5% rate is triggered at US$60 WCS with a sliding scale up to 15% at US$100 WCS. The Royalty is applied to Athabasca’s realized bitumen price (C$), which is determined net of storage and transportation costs.

(1) Based on the report of Athabasca's independent reserve evaluator effective December 31, 2024. Refer to the "Advisories and Other Guidance" section within this MD&A and the AIF for additional information about the Company's reserves and resources.

Leismer Operating Results

	Three months ended September 30, 2025	2024	Nine months ended September 30, 2025	2024
VOLUMES				
Bitumen production (bbl/d)	27,763	27,485	27,538	26,022
Bitumen sales (bbl/d)	27,417	27,891	27,490	26,044
Heavy oil (blended bitumen) sales (bbl/d)	37,962	38,258	39,385	36,971

($ Thousands, unless otherwise noted)	Three months ended September 30, 2025	2024	Nine months ended September 30, 2025	2024
Heavy oil (blended bitumen) sales	$ 251,526	$ 288,393	$ 807,104	$ 832,385
Cost of diluent	(92,960)	(103,883)	(325,687)	(329,543)
Total bitumen sales	158,566	184,510	481,417	502,842
Royalties	(8,247)	(17,910)	(28,219)	(49,606)
Operating expenses - non-energy	(18,447)	(18,835)	(57,728)	(55,714)
Operating expenses - energy	(6,012)	(6,623)	(24,767)	(25,976)
Transportation and marketing	(13,566)	(12,717)	(40,855)	(37,324)
LEISMER OPERATING INCOME(1)	$ 112,294	$ 128,425	$ 329,848	$ 334,222
REALIZED PRICE(1)				
Heavy oil (blended bitumen) sales ($/bbl)(1)	$ 72.02	$ 81.94	$ 75.06	$ 82.17
Bitumen sales ($/bbl)(1)	$ 62.86	$ 71.91	$ 64.15	$ 70.46
Royalties ($/bbl)(1)	(3.27)	(6.98)	(3.76)	(6.95)
Operating expenses - non-energy ($/bbl)(1)	(7.31)	(7.34)	(7.69)	(7.81)
Operating expenses - energy ($/bbl)(1)	(2.38)	(2.58)	(3.30)	(3.64)
Transportation and marketing ($/bbl)(1)	(5.38)	(4.96)	(5.44)	(5.23)
LEISMER OPERATING NETBACK ($/bbl)(1)	$ 44.52	$ 50.05	$ 43.96	$ 46.83

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures and production disclosure.

Leismer's bitumen production for the three and nine months ended September 30, 2025 was 27,763 bbl/d and 27,538 bbl/d, an increase of 1% and 6%, respectively, compared to the corresponding periods in 2024. The production increase is attributed to the completion of the facility expansion mid-year 2024 and the addition of new well pairs.

Total operating expenses were $9.69/bbl in the third quarter of 2025 and $10.99/bbl in the first nine months of 2025, compared to $9.92/bbl and $11.45/bbl for the same periods in 2024, respectively. The decrease on a per barrel basis is largely the result of higher production and lower energy costs.

Leismer's Operating Netback was $44.52/bbl and $43.96/bbl for the three and nine months ended September 30, 2025, respectively, representing a decrease of $5.53/bbl and $2.87/bbl compared with the same periods in 2024. The operating netback decrease is primarily a result of lower realized oil prices, partially offset by lower royalties and operating costs.

Hangingstone Operating Results

	Three months ended September 30, 2025	2024	Nine months ended September 30, 2025	2024
VOLUMES				
Bitumen production (bbl/d)	8,827	7,368	8,404	7,368
Bitumen sales (bbl/d)	8,401	7,922	8,205	7,286
Heavy oil (blended bitumen) sales (bbl/d)	11,882	10,766	11,867	10,176

($ Thousands, unless otherwise noted)	Three months ended September 30, 2025	2024	Nine months ended September 30, 2025	2024
Heavy oil (blended bitumen) and midstream sales	$ 78,016	$ 84,241	$ 239,973	$ 240,569
Cost of diluent	(29,051)	(26,082)	(95,521)	(82,448)
Total bitumen and midstream sales	48,965	58,159	144,452	158,121
Royalties	(2,345)	(4,381)	(7,768)	(13,045)
Operating expenses - non-energy	(5,437)	(6,068)	(17,853)	(16,731)
Operating expenses - energy	(3,141)	(3,371)	(11,514)	(12,211)
Transportation and marketing(1)	(7,705)	(9,070)	(23,415)	(24,519)
HANGINGSTONE OPERATING INCOME(2)	$ 30,337	$ 35,269	$ 83,902	$ 91,615
REALIZED PRICE(2)				
Heavy oil (blended bitumen) and midstream sales ($/bbl)(2)	$ 71.37	$ 85.05	$ 74.07	$ 86.28
Bitumen and midstream sales ($/bbl)(2)	$ 63.35	$ 79.80	$ 64.49	$ 79.20
Royalties ($/bbl)(2)	(3.03)	(6.01)	(3.47)	(6.53)
Operating expenses - non-energy ($/bbl)(2)	(7.03)	(8.33)	(7.97)	(8.38)
Operating expenses - energy ($/bbl)(2)	(4.06)	(4.63)	(5.14)	(6.12)
Transportation and marketing ($/bbl)(1)(2)	(9.97)	(12.44)	(10.45)	(12.28)
HANGINGSTONE OPERATING NETBACK ($/bbl)(2)	$ 39.26	$ 48.39	$ 37.46	$ 45.89

(1) Transportation and marketing excludes non-cash costs of $0.6 million and $1.7 million for the three and nine months ended September 30, 2025 (three and nine months ended September 30, 2024 - $0.6 million and $1.7 million).
(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures and production disclosure.

Hangingstone's bitumen production for the three and nine months ended September 30, 2025 was 8,827 bbl/d and 8,404 bbl/d, an increase of 20% and 14%, respectively, compared to the corresponding periods in 2024. The production increase is attributed to production from two new well pairs in March 2025.

Total operating expenses were $11.09/bbl in the third quarter of 2025 and $13.11/bbl in the first nine months of 2025, compared to $12.96/bbl and $14.50/bbl for the same periods in 2024, respectively. The decrease on a per barrel basis is the result of higher production and lower energy costs.

Hangingstone's Operating Netback was $39.26/bbl and $37.46/bbl for the three and nine months ended September 30, 2025, respectively, representing a decrease of $9.13/bbl and $8.43/bbl compared with the same periods in 2024. The decrease is primarily a result of lower realized oil prices partially offset by lower royalties, operating costs and transportation and marketing costs.

Athabasca (Thermal Oil) Operating Results

	Three months ended September 30, 2025	2024	Nine months ended September 30, 2025	2024
VOLUMES				
Bitumen production (bbl/d)	36,590	34,853	35,942	33,390
Bitumen sales (bbl/d)	35,818	35,813	35,695	33,330
Heavy oil (blended bitumen) sales (bbl/d)	49,844	49,024	51,252	47,147

($ Thousands, unless otherwise noted)	Three months ended September 30, 2025	2024	Nine months ended September 30, 2025	2024
Heavy oil (blended bitumen) and midstream sales	$ 329,542	$ 372,634	$ 1,047,077	$ 1,072,954
Cost of diluent	(122,011)	(129,965)	(421,208)	(411,991)
Total bitumen and midstream sales	207,531	242,669	625,869	660,963
Royalties	(10,592)	(22,291)	(35,987)	(62,651)
Operating expenses - non-energy	(23,884)	(24,903)	(75,581)	(72,445)
Operating expenses - energy	(9,153)	(9,994)	(36,281)	(38,187)
Transportation and marketing(1)	(21,271)	(21,787)	(64,270)	(61,843)
ATHABASCA (THERMAL OIL) OPERATING INCOME(2)	$ 142,631	$ 163,694	$ 413,750	$ 425,837
REALIZED PRICE(2)				
Heavy oil (blended bitumen) and midstream sales ($/bbl)(2)	$ 71.86	$ 82.62	$ 74.84	$ 83.06
Bitumen and midstream sales ($/bbl)(2)	$ 62.98	$ 73.65	$ 64.23	$ 72.38
Royalties ($/bbl)(2)	(3.21)	(6.77)	(3.69)	(6.86)
Operating expenses - non-energy ($/bbl)(2)	(7.25)	(7.56)	(7.76)	(7.93)
Operating expenses - energy ($/bbl)(2)	(2.78)	(3.03)	(3.72)	(4.18)
Transportation and marketing ($/bbl)(1)(2)	(6.46)	(6.61)	(6.60)	(6.77)
ATHABASCA (THERMAL OIL) OPERATING NETBACK ($/bbl)(2)	$ 43.28	$ 49.68	$ 42.46	$ 46.64

(1) Transportation and marketing excludes non-cash costs of $0.6 million and $1.7 million for the three and nine months ended September 30, 2025 (three and nine months ended September 30, 2024 - $0.6 million and $1.7 million).
(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures and production disclosure.

Seasonality can have an impact on Operating Income generated by the Thermal Oil business. In the first and fourth quarters of a given year, dilution costs will generally increase as more diluent is required to meet pipeline specifications.

Athabasca (Thermal Oil) Capital Expenditures

($ Thousands)	Three months ended September 30, 2025	2024	Nine months ended September 30, 2025	2024
Leismer Project	$ 61,490	$ 30,301	$ 159,125	$ 92,768
Hangingstone Project	2,189	13,624	10,340	25,453
Other	1,286	506	1,986	2,413
ATHABASCA (THERMAL OIL) CAPITAL EXPENDITURES(1)	$ 64,965	$ 44,431	$ 171,451	$ 120,634

(1) For the three and nine months ended September 30, 2025, capital expenditures include $1.7 million and $5.0 million of capitalized staff costs (three and nine months ended September 30, 2024 - $1.6 million and $4.7 million).

Thermal Oil capital expenditures were $171.5 million for the nine months ended September 30, 2025. At Leismer, the Company advanced its expansion project and field activity included facilities, pipeline construction on Pad 10 and 11, commencing steaming on Pad 10 (first two wells on production in July), drilling five observation wells and the completion of six redrills on Pad 1 with first production in March. At Hangingstone, the Company completed the conversion and steaming of two well pairs on Pad AA with first production in March.

DUVERNAY ENERGY[1]

Duvernay Energy, a privately held subsidiary of Athabasca, commenced operations on February 6, 2024 following the transfer of certain assets, pursuant to an agreement involving Athabasca and Cenovus Energy ("Cenovus") (the "Transaction"). Athabasca received a 70% equity interest in exchange for cash, petroleum and natural gas assets and the transferred interest of its wholly owned Kaybob partnership. Cenovus received a 30% equity interest in exchange for cash and petroleum and natural gas assets. Duvernay Energy is managed by Athabasca through a management and operating services agreement. With the completion of the Transaction, the former Light Oil operating segment has been renamed Duvernay Energy and with Duvernay Energy operating as a subsidiary under Athabasca's control it is consolidated within the Consolidated Financial Statements.

Duvernay Energy produces light oil and liquids-rich natural gas from unconventional reservoirs. Development has been focused on the Duvernay shale play in the Greater Kaybob area near the town of Fox Creek, Alberta. As at December 31, 2024, the Greater Kaybob assets had approximately 73 MMboe of Proved plus Probable Reserves[2]. The Duvernay Energy assets are supported by operated regional infrastructure consisting of two batteries and a network of gas pipelines which connect the facilities to two regional third party gas processing plants.

In Greater Kaybob, Duvernay Energy has approximately 200,000 gross acres of commercially prospective Duvernay lands with exposure to both Liquids-rich gas and volatile oil opportunities. This land is comprised of a 100% operated interest in approximately 46,000 gross acres and a 30% non-operated interest in approximately 155,000 gross acres with an estimated inventory of 444[3] gross drilling locations.

(1) Duvernay Energy reflects gross production and financial metrics before taking into consideration Athabasca's 70% equity interest in Duvernay Energy.
(2) Based on the report of Athabasca's independent reserve evaluator effective December 31, 2024. Refer to the "Advisories and Other Guidance" section within this MD&A and the AIF for additional information about the Company's reserves and resources.
(3) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information regarding the Company's drilling locations.

Duvernay Energy Operating Results

	Three months ended September 30, 2025	2024	Nine months ended September 30, 2025	2024
PRODUCTION[1]				
Oil and condensate (bbl/d)	2,053	2,688	1,834	2,235
Natural gas (Mcf/d)	4,563	5,526	4,578	4,511
Other natural gas liquids (bbl/d)	196	447	268	298
Total (boe/d)	3,009	4,056	2,865	3,285
% Liquids	75%	77%	73%	77%

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on production disclosure.

($ Thousands, unless otherwise noted)	Three months ended September 30, 2025	2024	Nine months ended September 30, 2025	2024
Petroleum and natural gas sales	$ 15,840	$ 24,728	$ 46,985	$ 63,015
Royalties	(1,271)	(2,470)	(5,824)	(8,282)
Operating expenses	(4,280)	(4,684)	(12,936)	(12,387)
Transportation and marketing	(1,085)	(1,084)	(2,843)	(3,113)
DUVERNAY ENERGY OPERATING INCOME[1]	$ 9,204	$ 16,490	$ 25,382	$ 39,233
REALIZED PRICES[1]				
Oil and condensate ($/bbl)[1]	$ 79.87	$ 93.29	$ 84.81	$ 95.70
Natural gas ($/Mcf)[1]	0.73	0.74	1.76	1.44
Other natural gas liquids ($/bbl)[1]	25.03	31.08	31.74	32.16
Realized price ($/boe)[1]	57.22	66.27	60.07	70.01
Royalties ($/boe)[1]	(4.59)	(6.62)	(7.45)	(9.20)
Operating expenses ($/boe)[1]	(15.46)	(12.55)	(16.54)	(13.76)
Transportation and marketing ($/boe)[1]	(3.92)	(2.90)	(3.63)	(3.46)
DUVERNAY ENERGY OPERATING NETBACK ($/boe)[1]	$ 33.25	$ 44.20	$ 32.45	$ 43.59

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures and production disclosure.

Duvernay Energy production for the three and nine months ended September 30, 2025 was 3,009 boe/d and 2,865 boe/d, a decrease of 26% and 13%, respectively, compared to the corresponding periods in 2024. The production decrease is primarily attributed to natural declines, partially offset by new production associated with the four gross (1.2 net) wells that were placed on production in the third quarter of 2025. The Company expects production growth following the completion and tie-in of a three gross (3.0 net) well pad in the fourth quarter of 2025.

Duvernay Energy's Operating Netback was $33.25/boe and $32.45/boe for the three and nine months ended September 30, 2025, respectively. The decrease on a per boe basis from the comparable 2024 periods is largely the result of lower realized oil and liquids prices and higher operating costs, partially offset by lower royalties.

Duvernay Energy Capital Expenditures

($ Thousands)	Three months ended September 30, 2025	2024	Nine months ended September 30, 2025	2024
DUVERNAY ENERGY CAPITAL EXPENDITURES[(1)]	$ 31,225	$ 6,203	$ 61,138	$ 54,464

(1) For the three and nine months ended September 30, 2025, capital expenditures include $0.6 million and $2.2 million of capitalized staff costs (three and nine months ended September 30, 2024 - $0.5 million and $1.4 million).

For the nine months ended September 30, 2025, Duvernay Energy's capital expenditures of $61.1 million were focused on drilling and completing a four well pad (30% working interest), which was placed on production in the third quarter; and completion activities on a three well pad (100% working interest), which is expected to be placed on production in the fourth quarter of 2025. Capital expenditures last winter also included the construction of a pipeline connecting the Duvernay Energy south lands to the Kaybob East Facility and construction of regional water infrastructure to support future development plans.

CORPORATE REVIEW

Liquidity and Capital Resources

Funding

For the balance of 2025, it is anticipated that Athabasca's capital and operating activities will be funded through cash flow from operating activities and existing credit facilities and cash and cash equivalents. The Company is directing Free Cash Flow to share buybacks and high return growth projects. Maintaining sufficient liquidity and a commodity risk management program is expected to allow the Company to manage periods of volatility.

As at September 30, 2025, Athabasca had Liquidity of $466.0 million which included $334.6 million of cash and cash equivalents, all within Athabasca (Thermal Oil), and $131.4 million of available capacity on its credit facilities (comprised of $83.5 million Athabasca (Thermal Oil) and $47.9 million Duvernay Energy).

Indebtedness

Athabasca had the following debt instruments and credit facilities in place as at September 30, 2025:

Term Debt

On August 9, 2024, Athabasca fully repaid its US$157 million ($215.6 million) of Senior Secured Second Lien Notes (the "2026 Notes") using the net proceeds of $195.5 million from the August 9, 2024 issuance of its $200 million Senior Unsecured Notes ("2029 Notes") and cash on hand. The 2029 Notes bear interest at 6.75% per annum, payable semi-annually, and have a term of 5 years maturing on August 9, 2029.

The 2029 Notes are unsecured, ranking equal in right of payment to all existing and future unsecured indebtedness, and are not subject to any maintenance or financial covenants. The 2029 Notes contain certain covenants that limit the Company's ability to, among other things, incur additional indebtedness, create or permit liens to exist, and make certain restricted payments, dispositions and transfers of assets. As at September 30, 2025, the Company is in compliance with all covenants.

Athabasca may redeem all or part of the 2029 Notes at any time prior to August 9, 2026 at 100% of the principal amount plus an applicable premium, as set out in the 2029 Notes indenture. On or after August 9, 2026, Athabasca may redeem all or part of the 2029 Notes at 103.375% from August 9, 2026 to August 8, 2027, at 101.688% from August 9, 2027 to August 8, 2028, and at 100% from August 9, 2028 onwards.

Credit Facility

Athabasca has a $110.0 million reserve-based credit facility (the "Credit Facility"). The Credit Facility is a committed facility available on a revolving basis until May 31, 2027, at which point in time it may be extended at the lender's option. The Credit Facility is subject to an annual borrowing base review, occurring by May 31 of each year. The borrowing base is determined based on the lender's evaluation of the Company's petroleum and natural gas reserves and their commodity price outlook at the time of each renewal. As at September 30, 2025 and December 31, 2024, the Company had no amounts drawn and $41.1 million of letters of credit outstanding under the Credit Facility.

Unsecured Letter of Credit Facility

Athabasca maintains a $75.0 million unsecured letter of credit facility (the "Unsecured Letter of Credit Facility") with a Canadian bank that is supported by a performance security guarantee from Export Development Canada. The facility is available on a demand basis and letters of credit issued under this facility incur an issuance and performance guarantee fee of 3.25%. As at September 30, 2025, the Company had $60.4 million of letters of credit outstanding under the Unsecured Letter of Credit Facility (December 31, 2024 - $56.4 million).

Duvernay Energy Credit Facility

Duvernay Energy has a $50.0 million reserve-based credit facility (the "Duvernay Credit Facility"). The Duvernay Credit Facility is a committed facility available on a revolving basis until November 30, 2025, at which point in time it may be extended at the lender's option. If the revolving period is not extended, the undrawn portion of the facility will be cancelled and any amounts outstanding would be repayable at the end of the non-revolving term, being November 30, 2026. The Duvernay Credit Facility is subject to a semi-annual borrowing base review, occurring by May 31 and November 30 of each year. The borrowing base is determined based on the lender's evaluation of the Company's petroleum and natural gas reserves and their commodity price outlook at the time of each renewal. As at September 30, 2025, the Company had $1.7 million drawn and $0.4 million of letters of credit outstanding under the Duvernay Credit Facility. As at December 31, 2024, the Company had no amounts drawn and $1.2 million of letters of credit outstanding under the Duvernay Credit Facility.

Financing and Interest

($ Thousands)	Three months ended September 30, 2025	2024	Nine months ended September 30, 2025	2024
Financing and interest expense on indebtedness	$ 4,603	$ 5,231	$ 13,840	$ 17,954
2026 Notes redemption premium	—	12,530	—	12,530
Accretion and loss on extinguishment of 2026 Notes	—	23,899	—	27,942
Accretion of 2029 Notes	201	104	585	104
Accretion of warrants	—	154	—	187
Accretion of provisions	2,178	1,999	6,426	5,892
Interest expense on lease liability	83	96	243	319
TOTAL FINANCING AND INTEREST	$ 7,065	$ 44,013	$ 21,094	$ 64,928

On August 9, 2024 the Company redeemed the 2026 Notes and paid a term debt redemption premium of $12.5 million, in addition as a result of the early redemption of the 2026 Notes a $23.2 million loss on extinguishment was expensed for the three months and nine months ended September 30, 2024.

Foreign Exchange Gain (Loss), Net

($ Thousands)	Three months ended September 30, 2025	2024	Nine months ended September 30, 2025	2024
Unrealized foreign exchange gain (loss)	$ 5,525	$ 20,891	$ (8,541)	$ 23,620
Realized foreign exchange gain (loss)	1,945	(23,834)	(2,098)	(22,060)
FOREIGN EXCHANGE GAIN (LOSS), NET	$ 7,470	$ (2,943)	$ (10,639)	$ 1,560

Athabasca is exposed to foreign currency risk on its US dollar denominated cash, cash equivalents, receivables and payables.

Risk Management Contracts

The Company may utilize financial and/or physical delivery contracts to fix the commodity price associated with a portion of its future production in order to manage its exposure to fluctuations in commodity prices.

Financial commodity risk management contracts are valued on the consolidated balance sheet by multiplying the contractual volumes by the differential between the anticipated market price (i.e. forecasted strip price) and the contractual fixed price at each future settlement date. The corresponding change in the asset or liability is recognized as an unrealized gain or loss in net income (loss). As the commodity derivatives are unwound (i.e. settled in cash), the Company recognizes a corresponding realized gain or loss in net income (loss). Physical delivery contracts are not considered financial instruments and therefore, no asset or liability is recognized on the consolidated balance sheet.

Financial commodity risk management contracts

At September 30, 2025, the following financial commodity risk management contracts were in place for Athabasca (Thermal Oil):

Instrument	Period	Volume		C$ Average Price(1)		US$ Average Price(1)
Sales contracts				*C$/bbl*		*US$/bbl*
WCS fixed price differential swaps	October - December 2025	6,000 bbl/d	$	18.71	$	13.44
WTI fixed price swaps	October - December 2025	5,000 bbl/d	$	97.59	$	70.10
Purchase contracts				*C$/GJ/bbl*		*US$/GJ/bbl*
AECO fixed price swaps	October - December 2025	27,000 GJ/d	$	2.02	$	1.45
AECO fixed price swaps	January - December 2026(2)	25,000 GJ/d	$	2.79	$	2.00
C5+ fixed price differential swaps	October - December 2025	2,000 bbl/d	$	1.50	$	1.08

(1) The implied C$ or US$ average price per bbl or GJ, as applicable, was calculated using the September 30, 2025 exchange rate of US$1.00 = C$1.3921.
(2) Excludes May 2026 due to the planned Thermal Oil turnarounds.

Additional financial commodity risk management has taken place subsequent to September 30, 2025 as noted in the table below:

Instrument	Period	Volume		C$ Average Price(1)		US$ Average Price(1)
Sales contracts				*C$/bbl*		*US$/bbl*
WCS fixed price differential swaps	January - March 2026	2,000 bbl/d	$	17.40	$	12.50
Purchase contracts				*C$/bbl*		*US$/bbl*
C5+ fixed price differential swaps	January - December 2026(2)	1,000 bbl/d	$	2.78	$	2.00

(1) The implied C$ or US$ average price per bbl or GJ, as applicable, was calculated using the September 30, 2025 exchange rate of US$1.00 = C$1.3921.
(2) Excludes May 2026 due to the planned Thermal Oil turnarounds.

In 2021, Athabasca (Thermal Oil) entered into a seven-year marketing agreement with an industry counterparty that diversifies the Company's sales to the US Gulf Coast through the Keystone pipeline system. The marketing agreement has a pricing derivative that provides exposure to WCS Gulf Coast pricing. As at September 30, 2025, the pricing derivative had a liability value of $0.2 million (December 31, 2024 - asset value of $3.3 million).

The following table summarizes the sensitivity to price changes for the Company's commodity risk management contracts for Athabasca (Thermal Oil):

	Change in WTI		Change in WCS differential		Change in AECO		Change in C5 differential	
As at September 30, 2025	Increase of US$5.00/bbl	Decrease of US$5.00/bbl	Increase of US$1.00/bbl	Decrease of US$1.00/bbl	Increase of C$1.00/GJ	Decrease of C$1.00/GJ	Increase of US$1.00/GJ	Decrease of US$1.00/GJ
Increase (decrease) to fair value of commodity risk management contracts	$ (3,190)	$ 3,190	$ (766)	$ 766	$ 4,717	$ (4,717)	$ 254	$ (254)

At September 30, 2025, the following financial commodity risk management contracts were in place for Duvernay Energy:

Instrument	Period	Volume		C$ Average Price(1)		US$ Average Price(1)
Sales contracts				*C$/bbl*		*US$/bbl*
WTI fixed price swaps	October - December 2025	825 bbl/d	$	87.68	$	62.98
WTI fixed price swaps	January - March 2026	825 bbl/d	$	87.24	$	62.67
WTI fixed price swaps	April - June 2026	825 bbl/d	$	88.05	$	63.25
WTI fixed price swaps	July - September 2026	725 bbl/d	$	87.84	$	63.10
WTI collars	October - December 2025	825 bbl/d	$	83.53 - 90.33	$	60.00 - 64.89
WTI collars	January - March 2026	825 bbl/d	$	83.53 - 89.26	$	60.00 - 64.12
WTI collars	April - June 2026	825 bbl/d	$	83.53 - 91.67	$	60.00 - 65.85
WTI collars	July - September 2026	725 bbl/d	$	83.53 - 90.83	$	60.00 - 65.25

(1) The implied C$ or US$ Average Price per bbl or GJ, as applicable, was calculated using the September 30, 2025 exchange rate of US$1.00 = C$1.3921.

The following table summarizes the sensitivity to price changes for the Company's commodity risk management contracts for Duvernay Energy:

As at September 30, 2025	Change in WTI Increase of US$5.00/bbl	Decrease of US$5.00/bbl
Increase (decrease) to fair value of commodity risk management contracts	$ (2,573)	$ 3,482

The following table summarizes the Company's net loss on commodity risk management contracts for the three and nine months ended September 30, 2025 and 2024:

($ Thousands)	Three months ended September 30, 2025	2024	Nine months ended September 30, 2025	2024
Unrealized gain (loss) on commodity risk mgmt. contracts	$ 3,471	$ 2,203	$ 1,925	$ (1,483)
Realized loss on commodity risk mgmt. contracts	(7,185)	(4,429)	(8,434)	(4,559)
LOSS ON COMMODITY RISK MGMT. CONTRACTS, NET	$ (3,714)	$ (2,226)	$ (6,509)	$ (6,042)

Commitments

The following table summarizes Athabasca’s estimated future unrecognized minimum commitments as at September 30, 2025 for the following five years and thereafter:

($ Thousands)	Remaining 2025	2026	2027	2028	2029	Thereafter	Total
Transportation and processing(1)	$ 28,182	$ 120,377	$ 149,575	$ 131,189	$ 120,468	$ 1,697,753	$ 2,247,544
Interest expense on 2029 Notes	3,375	13,500	13,500	13,500	8,174	—	52,049
Purchase commitments and other(1)	38,046	5,211	—	—	—	—	43,257
TOTAL COMMITMENTS	$ 69,603	$ 139,088	$ 163,075	$ 144,689	$ 128,642	$ 1,697,753	$ 2,342,850

(1) Commitments which are denominated in US dollars were translated into Canadian dollars at the September 30, 2025 exchange rate of US$1.00 = C$1.3921.

Credit Risk

Credit risk is the risk of financial loss to Athabasca if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from Athabasca’s cash balances, accounts receivables from petroleum and natural gas marketers, joint interest partners and risk management contract counterparties.

Athabasca’s cash and cash equivalents are held with two counterparties, which are large reputable financial institutions, and management concluded that credit risk associated with the investments is low. Management concluded that collection risk of the outstanding accounts receivables is low given the high credit quality of the Company's material counterparties. No material receivables were past due as at September 30, 2025. Athabasca's risk management contracts are held with three counterparties, all of which are large reputable financial institutions, and management concluded that credit risk associated with these risk management contracts is low.

Interest Rate Risk

The Company has exposure to interest rate fluctuations on its floating rate cash and cash equivalents balance at September 30, 2025 of $334.6 million (December 31, 2024 - $344.8 million). A 1.0% change in interest rates would have an annualized impact of approximately $3.3 million (year ended December 31, 2024 - $3.4 million) on interest income. The 2029 Notes and letters of credit issued are subject to fixed interest rates and are not exposed to changes in interest rates.

Duvernay Energy is exposed to interest rate fluctuations on its floating rate long-term debt balance at September 30, 2025 of $1.7 million (December 31, 2024 - $nil). Amounts borrowed under the Duvernay Credit Facility bear interest at a floating rate based on the applicable Canadian prime rate, US base rate, SOFR or CORRA, plus a margin of 2.00% to 3.00%. Changes in interest rates could result in an increase or decrease in the amount Duvernay Energy pays to service the Duvernay Credit Facility. Letters of credit are subject to fixed interest rates and are not exposed to changes in interest rates. A 1.0% change in interest rates would have an annualized impact of approximately $0.1 million (December 31, 2024 - $nil) on financing and interest expense.

Other Corporate Items

General and Administrative ("G&A")

($ Thousands, unless otherwise noted)	Three months ended September 30, 2025	2024	Nine months ended September 30, 2025	2024
TOTAL GENERAL AND ADMINISTRATIVE	$ 5,722	$ 4,925	$ 17,194	$ 16,509
G&A per boe[1]	$ 1.57	$ 1.38	$ 1.62	$ 1.64

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

Stock Based Compensation

During the three and nine months ended September 30, 2025, Athabasca's stock-based compensation expense was $10.6 million and $23.3 million, respectively, compared to $1.9 million and $21.6 million in the respective prior year periods. Stock-based compensation expense is impacted by the changes in the fair value of the cash settled stock-based compensation plans as a result of the share price changes in the respective periods.

Depletion and Depreciation

For the three and nine months ended September 30, 2025, Athabasca's depletion and depreciation expense was $32.9 million and $95.3 million compared to $31.6 million and $84.9 million in the respective prior year periods. The year over year increase is a result of the impact on the Hangingstone depletion and depreciation cost basis related to the December 31, 2024 impairment reversal and higher production at Leismer and Hangingstone.

Loss on Revaluation of Provisions and Other

($ Thousands)	Three months ended September 30, 2025	2024	Nine months ended September 30, 2025	2024
Change in fair value of warrant liability	$ (6,735)	$ 2,723	$ (8,671)	$ (3,773)
Change in estimated decommissioning obligations on fully impaired assets	—	(5,674)	—	(5,674)
LOSS ON REVALUATION OF PROVISIONS AND OTHER	$ (6,735)	$ (2,951)	$ (8,671)	$ (9,447)

The warrants are classified as a financial liability due to the cashless exercise provision and are therefore revalued quarterly. The changes in the fair value of the warrant liability in 2025 and 2024 primarily relate to changes in the share price.

Income Taxes

In the first nine months of 2025, as a result of net income before tax of $263.0 million, $63.8 million of income tax expense was recorded (first nine months of 2024 - $62.7 million expense). At September 30, 2025, the Company recognized a deferred tax asset of $246.9 million (December 31, 2024 - $307.3 million) and a deferred tax liability of $44.1 million (December 31, 2024 - $42.6 million). The Company has approximately $2.1 billion in tax pools, including approximately $1.6 billion in non-capital loss tax pools available for immediate deduction against future income.

Environmental and Regulatory Risks Impacting Athabasca

Athabasca operates in jurisdictions that have regulated greenhouse gas ("GHG") emissions and other air pollutants. While some regulations are in effect, further changes and amendments are at various stages of review, discussion and implementation. There is uncertainty around how any future federal legislation will harmonize with provincial regulation, as well as the timing and effects of regulations. Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulatory environment of the crude oil and natural gas industry in Canada. Such regulations impose certain costs and risks on the industry, and there remains some uncertainty with regard to the impacts of federal or provincial climate change and environmental laws and regulations, as such Athabasca is unable to predict additional legislation or amendments that governments may enact in the future. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on the Company's assets, operations and cash flow.

Off Balance Sheet Arrangements

The Company does not have any off-balance sheet arrangements that have or are reasonably likely to have a material current or future effect on the Company’s consolidated financial statements.

Outstanding Share Data

As at September 30, 2025, there were 488.8 million common shares outstanding, 3.6 million restricted share units outstanding, 2.6 million performance share units outstanding, 2.5 million stock options outstanding and 6.7 million potential shares issuable under warrants agreements (29,324 warrants outstanding).

In the first quarter of 2025, the Company renewed its NCIB with approval to purchase up to 50.4 million common shares during the twelve-month period commencing on March 18, 2025 and ending March 17, 2026. The Company fully completed its previous NCIB and purchased and cancelled a total of 55.4 million common shares for the twelve-month period ended March 17, 2025.

During the first nine months of 2025, the Company repurchased for cancellation 31.6 million common shares under its NCIB program. Subsequent to September 30, 2025, the Company repurchased for cancellation 2.6 million common shares under its NCIB program.

As at October 29, 2025, there were 486.2 million common shares outstanding, 3.6 million restricted share units outstanding, 2.6 million performance share units outstanding, 2.5 million stock options outstanding and 6.7 million potential shares issuable under warrants agreements (29,324 warrants outstanding).

SUMMARY OF QUARTERLY RESULTS

The following table summarizes selected consolidated financial information for the Company for the preceding eight quarters:

	2025			2024				2023
($ Thousands, unless otherwise noted)	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	64.93	63.74	71.42	70.27	75.09	80.57	76.96	78.32
WTI (C$/bbl)	89.43	88.21	102.47	98.29	102.39	110.25	103.80	106.65
Western Canadian Select (C$/bbl)	75.11	73.96	84.30	80.74	83.91	91.59	77.73	76.92
Edmonton Par (C$/bbl)	86.18	84.13	95.30	94.91	97.85	105.32	92.21	99.71
Edmonton Condensate (C5+) (C$/bbl)	86.43	87.42	99.65	98.25	96.49	104.85	97.36	102.83
AECO (C$/GJ)	0.60	1.60	2.05	1.40	0.65	1.12	2.36	2.18
Foreign exchange (USD : CAD)	1.38	1.38	1.43	1.40	1.36	1.37	1.35	1.36
CORPORATE CONSOLIDATED[1]								
Petroleum and natural gas production (boe/d)[2]	39,599	39,088	37,714	37,236	38,909	37,621	33,470	33,127
Realized price (net of cost of diluent) ($/boe)[2]	62.53	60.70	68.98	67.27	72.90	79.93	62.18	57.86
Petroleum, natural gas and midstream sales ($)[3]	345,382	368,686	379,994	366,895	397,362	422,028	316,579	321,737
Operating Income ($)[2]	151,835	141,707	145,590	155,022	180,184	179,751	105,135	96,960
Operating Income Net of Realized Hedging ($)[2]	144,650	142,101	143,947	153,119	175,755	178,176	106,580	91,443
Operating Netback ($/boe)[2]	42.50	38.81	44.07	45.53	49.12	52.46	35.78	30.44
Operating Netback Net of Realized Hedging ($/boe)[2]	40.49	38.92	43.57	44.97	47.91	52.00	36.27	28.71
Capital expenditures ($)	96,190	73,066	63,333	92,944	50,634	48,453	76,011	38,752
Cash flow from operating activities ($)	157,414	101,432	123,353	158,677	187,143	135,083	76,638	103,196
Adjusted Funds Flow ($)[2]	129,197	127,591	129,675	143,737	163,680	165,746	87,772	81,830
ATHABASCA (THERMAL OIL)								
Bitumen production (bbl/d)	36,590	36,476	34,742	33,849	34,853	33,765	31,536	31,059
Bitumen sales volumes (bbl/d)	35,818	37,511	33,733	33,628	35,813	33,794	30,358	32,552
Realized bitumen price ($/bbl)[2]	62.98	60.96	69.25	67.52	73.65	80.36	61.96	57.31
Heavy Oil (blended bitumen) and midstream sales ($)	329,542	355,160	362,375	346,716	372,634	395,279	305,041	309,078
Operating Income ($)[2]	142,631	135,803	135,316	143,246	163,694	161,694	100,449	92,199
Operating Netback ($/bbl)[2]	43.28	39.79	44.56	46.30	49.68	52.59	36.36	30.78
Capital expenditures ($)	64,965	56,110	50,376	74,268	44,431	34,084	42,119	29,371
Adjusted Funds Flow ($)[2]	121,131	122,097	121,353	133,398	150,088	149,413	83,713	
Free Cash Flow ($)[2]	56,166	65,987	70,977	59,130	105,657	115,329	41,594	
DUVERNAY ENERGY[1]								
Petroleum and natural gas production (boe/d)[2]	3,009	2,612	2,972	3,387	4,056	3,856	1,934	2,068
Realized price ($/boe)[2]	57.22	56.91	65.87	64.76	66.27	76.23	65.56	66.54
Petroleum and natural gas sales ($)[3]	15,840	13,526	17,619	20,179	24,728	26,749	11,538	12,659
Operating Income ($)[2]	9,204	5,904	10,274	11,776	16,490	18,057	4,686	4,761
Operating Netback ($/boe)[2]	33.25	24.84	38.42	37.79	44.20	51.46	26.63	25.02
Capital expenditures ($)	31,225	16,956	12,957	18,676	6,203	14,369	33,892	9,381
Adjusted Funds Flow ($)[2]	8,066	5,494	8,322	10,339	13,592	16,333	4,059	
Free Cash Flow ($)[2]	(23,159)	(11,462)	(4,635)	(8,337)	7,389	1,964	(29,833)	
OPERATING RESULTS								
Net income ($)[4]	69,640	56,870	72,004	264,336	68,722	96,076	38,609	27,506
Net income per share - basic ($)[4]	0.14	0.11	0.14	0.50	0.13	0.17	0.07	0.05
BALANCE SHEET ITEMS								
Cash and cash equivalents ($)	334,550	304,048	304,538	344,836	334,851	303,360	306,503	343,309
Total assets ($)	2,532,553	2,475,675	2,457,126	2,474,609	2,234,651	2,230,648	2,208,094	2,048,635
Long-term debt ($)	198,084	196,217	196,022	195,833	195,642	190,986	186,773	179,705
Shareholders' equity ($)	1,898,145	1,889,887	1,866,431	1,863,732	1,674,942	1,687,741	1,665,552	1,583,453

(1) Corporate Consolidated and Duvernay Energy reflect gross production and financial metrics before taking into consideration Athabasca's 70% equity interest in Duvernay Energy.
(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures and production disclosure.
(3) Includes intercompany NGLs (i.e. condensate) sold by the Duvernay Energy segment to the Athabasca (Thermal Oil) segment for use as diluent that is eliminated on consolidation.
(4) Net income per share amounts are based on net income attributable to shareholders of the Parent Company.

Refer to the Results of Operations and other sections of this MD&A for detailed financial and operational variances between reporting periods as well as to Athabasca's previously issued annual and quarterly MD&As for changes in prior periods.

ACCOUNTING POLICIES AND ESTIMATES

During the nine months ended September 30, 2025, there were no changes to Athabasca's accounting policies or use of estimates and judgments in the preparation of the Consolidated Financial Statements and the notes thereto. A summary of the significant accounting policies, including the use of estimates and judgments, used by Athabasca can be found in Note 3 of the December 31, 2024 audited consolidated financial statements. All of the estimates and judgments are subject to measurement uncertainty and changes in these estimates could materially impact the consolidated financial statements of future periods and have a significant impact on net income (loss) and comprehensive income (loss).

ADVISORIES AND OTHER GUIDANCE

Non-GAAP and Other Financial Measures, and Production Disclosure

The "Corporate Consolidated Adjusted Funds Flow", "Corporate Consolidated Adjusted Funds Flow per Share", "Athabasca (Thermal Oil) Adjusted Funds Flow", "Duvernay Energy Adjusted Funds Flow", "Corporate Consolidated Free Cash Flow", "Athabasca (Thermal Oil) Free Cash Flow", "Duvernay Energy Free Cash Flow", "Corporate Consolidated Operating Income", "Corporate Consolidated Operating Income Net of Realized Hedging", "Athabasca (Thermal Oil) Operating Income", "Duvernay Energy Operating Income", "Corporate Consolidated Operating Netback", "Corporate Consolidated Operating Netback Net of Realized Hedging", "Athabasca (Thermal Oil) Operating Netback", "Duvernay Energy Operating Netback", "Realized Prices" and "Cash Transportation and Marketing Expense" financial measures contained in this MD&A do not have standardized meanings which are prescribed by IFRS and they are considered to be non-GAAP financial measures or ratios. These measures may not be comparable to similar measures presented by other issuers and should not be considered in isolation with measures that are prepared in accordance with IFRS. The Liquidity and the per boe or per bbl disclosures for each segment's royalties, operating expenses, transportation and marketing, realized gain (loss) on commodity risk management contracts and G&A are supplementary financial measures. The Leismer and Hangingstone operating results are supplementary financial measures that when aggregated combine to the Athabasca (Thermal Oil) segment results.

Adjusted Funds Flow, Adjusted Funds Flow Per Share and Free Cash Flow

Adjusted Funds Flow and Free Cash Flow are non-GAAP financial measures and are not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS. The Adjusted Funds Flow and Free Cash Flow measures allow management and others to evaluate the Company's ability to fund its capital programs and meet its ongoing financial obligations using cash flow internally generated from ongoing operating related activities. Adjusted Funds Flow per share is a non-GAAP financial ratio calculated as Adjusted Funds Flow divided by the applicable number of weighted average shares outstanding.

Adjusted Funds Flow and Free Cash Flow are calculated as follows:

($ Thousands)	Three months ended September 30, 2025 Athabasca (Thermal Oil)	Duvernay Energy[1]	Corporate Consolidated[1]
Cash flow from operating activities	$ 151,690	$ 5,724	$ 157,414
Changes in non-cash working capital	(30,673)	2,337	(28,336)
Settlement of provisions	114	5	119
ADJUSTED FUNDS FLOW	121,131	8,066	129,197
Capital expenditures	(64,965)	(31,225)	(96,190)
FREE CASH FLOW	$ 56,166	$ (23,159)	$ 33,007

(1) Duvernay Energy and Corporate Consolidated reflect gross financial metrics before taking into consideration Athabasca's 70% equity interest in Duvernay Energy.

($ Thousands)		Nine months ended September 30, 2025 Athabasca (Thermal Oil)		Duvernay Energy[1]		Corporate Consolidated[1]
Cash flow from operating activities	$	366,259	$	15,940	$	382,199
Changes in non-cash working capital		(2,521)		5,932		3,411
Settlement of provisions		843		10		853
ADJUSTED FUNDS FLOW		364,581		21,882		386,463
Capital expenditures		(171,451)		(61,138)		(232,589)
FREE CASH FLOW	$	193,130	$	(39,256)	$	153,874

(1) Duvernay Energy and Corporate Consolidated reflect gross financial metrics before taking into consideration Athabasca's 70% equity interest in Duvernay Energy.

($ Thousands)		Three months ended September 30, 2024 Athabasca (Thermal Oil)		Duvernay Energy[1]		Corporate Consolidated[1]
Cash flow from operating activities	$	169,950	$	17,193	$	187,143
Changes in non-cash working capital		(20,201)		(3,401)		(23,602)
Settlement of provisions		339		(200)		139
ADJUSTED FUNDS FLOW		150,088		13,592		163,680
Capital expenditures		(44,431)		(6,203)		(50,634)
FREE CASH FLOW	$	105,657	$	7,389	$	113,046

(1) Duvernay Energy and Corporate Consolidated reflect gross financial metrics before taking into consideration Athabasca's 70% equity interest in Duvernay Energy.

($ Thousands)		Nine months ended September 30, 2024 Athabasca (Thermal Oil)		Duvernay Energy[1]		Corporate Consolidated[1]
Cash flow from operating activities	$	367,018	$	31,846	$	398,864
Changes in non-cash working capital		14,560		2,134		16,694
Settlement of provisions		1,636		4		1,640
ADJUSTED FUNDS FLOW		383,214		33,984		417,198
Capital expenditures		(120,634)		(54,464)		(175,098)
FREE CASH FLOW	$	262,580	$	(20,480)	$	242,100

(1) Duvernay Energy and Corporate Consolidated reflect gross financial metrics before taking into consideration Athabasca's 70% equity interest in Duvernay Energy.

Operating Income and Operating Netback

The non-GAAP measure Operating Income in this MD&A is calculated by subtracting the cost of diluent, royalties, operating expenses and cash transportation & marketing expenses from petroleum, natural gas and midstream sales which is the most directly comparable GAAP measure. The Operating Netback per boe is a non-GAAP financial ratio measure calculated by dividing the respective projects Operating Income by its respective sales volumes. The Operating Income and Operating Netback measures allow management and others to evaluate the production results from the Company’s assets.

The non-GAAP measure Corporate Consolidated Operating Income Net of Realized Hedging in this MD&A is calculated by adding or subtracting realized gains (losses) on commodity risk management contracts, royalties, the cost of diluent, operating expenses and cash transportation & marketing expenses from petroleum, natural gas and midstream sales which is the most directly comparable GAAP measure. The Corporate Consolidated Operating Netback Net of Realized Hedging measure per boe is a non-GAAP financial ratio calculated by dividing Corporate Consolidated Operating Income Net of Realized Hedging by the total sales volumes. The Corporate Consolidated Operating Income Net of Realized Hedging and the Corporate Consolidated Operating Netback Net of Realized Hedging measures allow management and others to evaluate the production results from the Company’s Duvernay Energy and Athabasca (Thermal Oil) assets combined together including the impact of realized commodity risk management gains or losses.

Realized Prices

The realized price financial measures contained in this MD&A are calculated by subtracting the cost of diluent from the petroleum, natural gas and midstream sales for the respective segment and are considered to be non-GAAP financial ratios.

Cash Transportation and Marketing Expense

The Cash Transportation and Marketing Expense financial measures contained in this MD&A are calculated by subtracting the non-cash transportation and marketing expense as reported in the Consolidated Statement of Cash Flows from the transportation and marketing expense as reported in the Consolidated Statement of Income (Loss) and are considered to be non-GAAP financial measures.

Supplementary Financial Measures

The supplementary financial measure Liquidity is defined as cash and cash equivalents plus available credit capacity.

Per boe or per bbl disclosures for each segment's royalties, operating expenses, transportation and marketing, realized gain (loss) on commodity risk management contracts and G&A are supplementary financial measures that are calculated by dividing the respective GAAP measure by its respective sales volumes.

Production volumes details

		Three months ended September 30,		Nine months ended September 30,	
Production		**2025**	**2024**	**2025**	**2024**
Duvernay Energy:					
Oil and condensate NGLs(1)	bbl/d	2,053	2,688	1,834	2,235
Other NGLs	bbl/d	196	447	268	298
Natural gas(2)	mcf/d	4,563	5,526	4,578	4,511
Total Duvernay Energy	boe/d	3,009	4,056	2,865	3,285
Total Thermal Oil bitumen	bbl/d	36,590	34,853	35,942	33,390
Total Company production	boe/d	39,599	38,909	38,807	36,675

(1) Comprised of 99% or greater of tight oil, with the remaining being light and medium crude oil.
(2) Comprised of 99% or greater of shale gas, with the remaining being conventional natural gas.

		Three months ended September 30,		Nine months ended September 30,	
Liquids:		**2025**	**2024**	**2025**	**2024**
Total Duvernay Energy:					
Oil and condensate NGLs	bbl/d	2,053	2,688	1,834	2,235
Other NGLs	bbl/d	196	447	268	298
Total Duvernay Energy Liquids	bbl/d	2,249	3,135	2,102	2,533
as % of Duvernay Energy production		75%	77%	73%	77%
Total Company:					
Total Duvernay Energy Liquids	bbl/d	2,249	3,135	2,102	2,533
Total Thermal Oil bitumen	bbl/d	36,590	34,853	35,942	33,390
Total Company Liquids	bbl/d	38,839	37,988	38,044	35,923
as % of Company production		98%	98%	98%	98%

This MD&A also makes reference to Athabasca's forecasted total average daily Thermal Oil production of approximately 35,500 bbl/d for 2025. Athabasca expects that 100% of that production will be comprised of bitumen. Duvernay Energy's forecasted total average daily production of approximately 3,500 boe/d for 2025 is expected to be comprised of approximately 68% tight oil, 23% shale gas and 9% NGLs.

Disclosure Control and Procedures

Athabasca is required to comply with National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109"). NI 52-109 requires that Athabasca disclose in its interim MD&A any material weaknesses in Athabasca's internal control over financial reporting and/or any changes in Athabasca's internal control over financial reporting that occurred during the period that have materially affected, or are reasonably likely to materially affect, Athabasca's internal controls over financial reporting. Athabasca confirms that no material weaknesses or such changes were identified in Athabasca's internal controls over financial reporting during the third quarter of 2025.

Risks

Factors currently influencing the Company's ability to succeed include, but are not limited to, the following:

Operational risks

- the performance of the Company's assets;
- reservoir impairment when shutting in or curtailing production from oil and gas assets;
- Athabasca's exploration and development budget and Athabasca's capital expenditure programs;
- failure to realize anticipated benefits of acquisitions or divestments;
- uncertainties inherent in estimating quantities of Proved Reserves, Probable Reserves and Contingent Resources;
- the timing of certain of Athabasca's operations and projects, including the commencement of its planned Thermal Oil development projects, the exploration and development of its Duvernay Energy assets and the levels and timing of anticipated production;
- dependence upon Murphy as the operator of the joint development Greater Kaybob assets;
- risks and uncertainties inherent in Athabasca's operations, including those related to exploration, development and production of reserves and resources;
- risks related to gathering and processing facilities and pipeline systems;
- reliance on third party infrastructure;
- supply chain disruption;
- seasonality and weather conditions, which may be impacted by climate change;
- risks associated with events of force majeure; and
- expiration of leases and permits or the failure of Athabasca or the holder of certain licenses, leases or permits to meet specific requirements of such licenses, leases or permits.

Planning risks

- the business strategy, objectives and business strengths of Athabasca;
- Athabasca's growth strategy and opportunities;
- Athabasca's plans to submit additional regulatory applications;
- Athabasca's drilling plans and plans and results regarding the completion of wells that have been drilled and other exploration and development activities;
- Athabasca's environment, social and governance goals;
- failure to accurately estimate abandonment and reclamation costs; and
- the potential for management estimates and assumptions to be inaccurate.

Financial and market risks

- general economic, market and business conditions in Canada, the United States and globally;
- future commodity market prices;
- Canadian heavy and light oil export capacity constraints and the resulting impact on realized pricing;
- Athabasca's projections of commodity prices, costs and netbacks;
- the substantial capital requirements of Athabasca's projects and the Company's ability to raise capital;
- risk of reduced capital availability due to environmental and climate related reputational issues for industry;
- the potential for future joint venture arrangements;
- insurance risks;
- hedging risks;
- variations in foreign exchange and interest rates;
- risks related to the Company's indebtedness;
- risks related to the Common Shares; and
- risks of cybersecurity threats including the possibility of potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of our information technology systems.

Legal and compliance risks

- the regulatory framework governing royalties, taxes, environmental matters and foreign investment in the jurisdictions in which Athabasca conducts and will conduct its business;
- risks related to Athabasca's filings with taxation authorities, including the risk of tax related reviews and reassessments;
- risks related to climate change and carbon pricing;

- actions taken by the American administration on the imposition of taxes on the importation of goods into the United States;
- aboriginal claims;
- risks associated with establishing and maintaining systems of internal controls;
- inaccuracy of forward-looking information; and
- risks related to the Government of Canada amendments to the deceptive marketing practices provisions of the *Competition Act* (Canada) that specifically address greenwashing.

For additional information regarding the risks and uncertainties to which the Company and its business are subject, please see the information under the headings “Forward Looking Information” below, and under the headings “Forward Looking Statements” and “Risk Factors” in the Company’s most recent AIF, on the Company’s SEDAR profile at www.sedarplus.ca.

Forward Looking Information

This MD&A contains forward-looking information that involves various risks, uncertainties and other factors. All information other than statements of historical fact is forward-looking information. The use of any of the words “anticipate”, "intend", “plan”, "outlook", "guidance", "estimate”, “expect”, “may”, “will”, “target”, “believe”, “predict”, “potential” and similar expressions are intended to identify forward-looking information. The forward-looking information is not historical fact, but rather is based on the Company’s current plans, objectives, goals, strategies, estimates, assumptions and projections about the Company’s industry, business and future financial results. This information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. No assurance can be given that these expectations will prove to be correct and such forward-looking information included in this MD&A should not be unduly relied upon. This information speaks only as of the date of this MD&A. In particular, this MD&A may contain forward-looking information pertaining to the following: the Company's future growth outlook and how that growth outlook is funded; estimates of Thermal Oil and Duvernay Energy production levels; reserve life index; on stream timing of wells and timing of expansion projects; the Company's anticipated sources of funding for 2025 and beyond; the Company's estimated future minimum commitments; the future allocation of capital; the Company’s ability to manage periods of volatility; Adjusted Funds Flow; Free Cash Flow; capital expenditures and other matters.

In addition, information and statements in this MD&A relating to “Reserves” and “Resources” are deemed to be forward-looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and that the reserves and resources described can be profitably produced in the future. Certain assumptions related to the Company’s Reserves and Resources are contained in the report of McDaniel & Associates Consultants Ltd. ("McDaniel") evaluating Athabasca’s Proved Reserves, Probable Reserves and Contingent Resources as at December 31, 2024 (which is respectively referred to herein as the "McDaniel Report”).

With respect to forward-looking information contained in this MD&A, assumptions have been made regarding, among other things: commodity prices; the regulatory framework governing royalties, taxes and environmental matters in the jurisdictions in which the Company conducts and will conduct business and the effects that such regulatory framework will have on the Company, including on the Company’s financial condition and results of operations; the Company’s financial and operational flexibility; the Company’s financial sustainability; the Company’s ability to obtain qualified staff and equipment in a timely and cost-efficient manner; the applicability of technologies for the recovery and production of the Company’s reserves and resources; future capital expenditures to be made by the Company; future sources of funding for the Company’s capital programs; the Company’s future debt levels; future production levels; the Company’s ability to obtain financing and/or enter into joint venture arrangements, on acceptable terms; operating costs; compliance of counterparties with the terms of contractual arrangements; impact of increasing competition globally; collection risk of outstanding accounts receivable from third parties; geological and engineering estimates in respect of the Company’s reserves and resources; recoverability of reserves and resources; the geography of the areas in which the Company is conducting exploration and development activities and the quality of its assets.

Actual results could differ materially from those anticipated in this forward-looking information as a result of the risk factors set forth in the Company’s most recent AIF available on SEDAR at www.sedarplus.ca, including, but not limited to: weakness in the oil and gas industry; exploration, development and production risks; prices, markets and marketing; market conditions; trade relations and tariffs; climate change and carbon pricing risk; statutes and regulations regarding the environment; regulatory environment and changes in applicable law; gathering and processing facilities, pipeline systems and rail; reputation and public perception of the oil and gas sector; environment, social and governance goals; political uncertainty; state of capital markets; ability to finance capital requirements; access to capital and insurance; abandonment and reclamation costs; changing demand for oil and natural gas products; anticipated benefits of acquisitions and dispositions; royalty regimes; foreign exchange rates and interest rates; reserves; hedging; operational dependence; operating costs; project risks; supply chain disruption; financial assurances; diluent supply; third party credit risk; indigenous claims; reliance on key personnel and operators; income tax; cybersecurity; advanced technologies; hydraulic fracturing; liability management; seasonality and weather conditions; unexpected events; internal controls; limitations of insurance; litigation; natural gas overlying bitumen resources; competition; chain of title and expiration of licenses and leases; breaches of confidentiality; new industry related activities or new geographical areas; water use restrictions and/or limited access to water; relationship with Duvernay Energy Corporation; management estimates and assumptions; third-party claims; conflicts of interest; inflation and cost management; credit ratings; growth management; impact of pandemics; ability of investors resident in the United States to enforce civil remedies in Canada; and risks related to our debt and securities.

The risks and uncertainties referred to above are described in more detail in Athabasca's most recent AIF, which is available on the Company's SEDAR profile at www.sedarplus.ca. Readers are cautioned that the foregoing list of risk factors should not be construed as exhaustive. The forward-looking information included in this MD&A is expressly qualified by this cautionary statement and is made as of the date of this MD&A. The Company does not undertake any obligation to publicly update or revise any forward-looking information except as required by applicable securities laws.

The Company's financial condition and results of operations discussed in this MD&A will not necessarily be indicative of the Company's future performance, particularly considering that many of the Company's activities are currently in the early stages of their planned exploration and/or development.

Reserves and Resource Information

The McDaniel Report was prepared using the assumptions and methodology guidelines outlined in the COGE Handbook and in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities,* effective December 31, 2024. There are numerous uncertainties inherent in estimating quantities of bitumen, light crude oil and medium crude oil, tight oil, conventional natural gas, shale gas and NGL reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth above are estimates only. In general, estimates of economically recoverable reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially. For those reasons, estimates of the economically recoverable reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. There is no certainty that it will be commercially viable to produce any portion of the resources. Reserves and Contingent Resources figures described herein have been rounded to the nearest MMbbl or MMboe. For additional information regarding the consolidated reserves and resources of the Company as evaluated by McDaniel in the McDaniel Report, please refer to the Company's AIF that is available on SEDAR at www.sedarplus.ca.

Oil and Gas Information

"Boe" may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent (6 Mcf: 1 bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Drilling Locations

The 444 gross Duvernay drilling locations referenced in this MD&A include: 87 proved undeveloped locations and 85 probable undeveloped locations for a total of 172 booked locations with the balance being unbooked locations. Proved undeveloped locations and probable undeveloped locations are booked and derived from the Company's most recent independent reserves evaluation as prepared by McDaniel as of December 31, 2024 and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal management estimates. Unbooked locations do not have attributed reserves or resources (including contingent or prospective). Unbooked locations have been identified by management as an estimation of Athabasca's multi-year drilling activities expected to occur over the next two decades based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, commodity prices, provincial fiscal and royalty policies, costs, actual drilling results, additional reservoir information that is obtained and other factors.

Definitions

"Best Estimate" is a classification of estimated resources described in the COGE Handbook as being considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the Best Estimate. If probabilistic methods are used, there should be a 50% probability (P50) that the quantities actually recovered will equal or exceed the Best Estimate.

"**Contingent Resources**" are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include such factors as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "Contingent Resources" the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources may be divided into the following project maturity sub-classes: "Development Pending" is assigned to Contingent Resources for a particular project where resolution of the final conditions for development is being actively pursued (high chance of development); "Development On Hold" is assigned to Contingent Resources for a particular project where there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator; "Development Unclarified" is assigned to Contingent Resources for a particular project where evaluation is incomplete and there is ongoing activity to resolve any risks or uncertainties or which require significant further appraisal to clarify potential for development and where contingencies have yet to be defined; "Development Not Viable" is assigned to Contingent Resources for a particular project where no further data acquisition or evaluation is currently planned and there is a low chance of development. As at December 31, 2024, the Company reported Contingent Resources on a risked and unrisked basis located in its Leismer and Corner asset areas in the Development Pending project maturity sub-class.

"Liquids" includes bitumen, light oil and medium oil, tight oil and NGLs, as applicable.

"Proved Reserves" are those reserves 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.

"Probable Reserves" are those additional reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved Reserves plus Probable Reserves.

"Reserve Life Index" is a measure of the estimated length of time it will take to deplete the Company's oil and gas reserves (typically reported in number of years).

"**Risked**" or **"risked"** means the applicable reported volumes or revenues have been risked (or adjusted) based on the chance of commerciality of such resources in accordance with the COGE Handbook. In accordance with the COGE Handbook for contingent resources, the chance of commerciality is solely based on the chance of development based on all contingencies required for the re-classification of the contingent resources as reserves being resolved. Therefore, risked reported volumes and values of contingent resources reflect the risking (or adjustment) of such volumes or values based on the chance of development of such resources.

"**Unrisked**" or **"unrisked"** means applicable reported volumes or values of resources have not been risked (or adjusted) based on the chance of commerciality of such resources. In accordance with the COGE Handbook for contingent resources, the chance of commerciality is solely based on the chance of development based on all contingencies required for the re-classification of the contingent resources as reserves being resolved. Therefore, unrisked reported volumes and values of contingent resources do not reflect the risking (or adjustment) of such volumes or values based on the chance of development of such resources.

Abbreviations

AECO	physical storage and trading hub for natural gas on the TC Alberta transmission system which is the delivery point for various benchmark Alberta index prices.
bbl	barrel
bbl/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
C$	Canadian Dollars
COGE	Canadian Oil and Gas Evaluation
GAAP	Generally Accepted Accounting Principles
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
Mgmt.	management
MMbbl	millions of barrels
MMboe	millions of barrels of oil equivalent
MMBtu	million British thermal units
NGL	Natural gas liquids
SAGD	steam assisted gravity drainage
US$	United States Dollars
WTI	West Texas Intermediate
WCS	Western Canadian Select