Management's Discussion and Analysis

December 31, 2024

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 March 5, 2025 and should be read in conjunction with the audited consolidated financial statements ("Consolidated Financial Statements") as at and for the years ended December 31, 2024 and 2023. 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".

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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.

HIGHLIGHTS FOR THE QUARTER AND YEAR ENDED DECEMBER 31, 2024

Corporate Consolidated(1)

- Production of 37,236 boe/d (98% Liquids(2)) in the fourth quarter and 2024 production of 36,815 boe/d (98% Liquids(2)). Representing growth of 12% (23% per basic share) and 7% (14% per basic share), compared to the respective corresponding periods in 2023.
- Petroleum, natural gas and midstream sales of $352.5 million in the fourth quarter and $1.4 billion for 2024.
- Operating Income(2) and Operating Netback(2) of $155.0 million ($45.53/boe) in the fourth quarter and $620.1 million ($46.14/boe) in 2024.
- Adjusted Funds Flow(2) of $143.7 million ($0.27 per share) in the fourth quarter and $560.9 million ($1.02 per share) in 2024 (cash flow from operating activities of $158.7 million in the fourth quarter and $557.5 million in 2024).
- In 2024 Athabasca completed the refinancing of its USD 9.75% 2026 Senior Secured Second Lien Notes through the issuance of $200 million of CAD 6.75% 2029 Senior Unsecured Notes.
- Liquidity(2) of $481.2 million, including $344.8 million of cash as at December 31, 2024.
- Repurchased and cancelled a total of 61.3 million common shares for $317.0 million in 2024, funded through Thermal Oil Free Cash Flow generation.

Athabasca (Thermal Oil)

- Fourth quarter production of 33,849 bbl/d and 2024 production of 33,505 bbl/d.
- Petroleum, natural gas and midstream sales of $346.7 million in the fourth quarter and $1.4 billion for 2024.
- Operating Income(2) and Operating Netback(2) of $143.2 million ($46.30/bbl) for the fourth quarter and $569.1 million ($46.54/bbl) for 2024.
- Adjusted Funds Flow(2) of $133.4 million for the fourth quarter and $516.6 million for 2024.
- Free Cash Flow(2) of $59.1 million for the fourth quarter and $321.7 million for 2024.
- 2024 capital expenditures of $194.9 million. At Leismer, the Company completed the facility expansion project that supported growth to approximately 28,000 bbl/d mid-year and commenced the progressive growth program to 40,000 bbl/d. Activity included further development of Pad 8 (four additional well pairs), three redrills on Pad 4, the tie-in of four infill wells on Pad 7, drilling and completions operations of four well pairs at Pad 10, six redrills on Pad 1 and the commencement of construction at Pad 11. At Hangingstone, the Company completed the drilling and completion of two sustaining well pairs on Pad AA that commenced steaming in the fourth quarter of 2024 with first production expected in early 2025.

Duvernay Energy(1)

- Fourth quarter production of 3,387 boe/d (75% Liquids(2)) and 2024 production of 3,310 boe/d (76% Liquids(2)).
- Petroleum, natural gas and midstream sales of $20.2 million in the fourth quarter and $83.2 million for 2024.
- Operating Income(2) and Operating Netback(2) of $11.8 million ($37.79/boe) for the fourth quarter and $51.0 million ($42.10/boe) for 2024.
- Adjusted Funds Flow(2) of $10.3 million for the fourth quarter and $44.3 million for 2024.
- 2024 capital expenditures of $73.1 million, with activity focused on drilling and completions on a two well pad (100% working interest) and drilling and completions on a three well pad (30% working interest), which were both placed on production in the second quarter of 2024. Activity also included drilling a three well pad (100% working interest) that is expected to be completed and placed on production in 2025 and preliminary work on the pipeline connecting the Duvernay Energy south lands to the Kaybob East Facility.

(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 December 31, 2024	2023	Year ended December 31, 2024	2023
CORPORATE CONSOLIDATED(1)				
Petroleum and natural gas production (boe/d)(2)	37,236	33,127	36,815	34,490
Petroleum, natural gas and midstream sales	$ 352,456	$ 315,929	$ 1,442,091	$ 1,268,525
Operating Income(2)	$ 155,022	$ 96,960	$ 620,092	$ 417,023
Operating Income Net of Realized Hedging(2)(3)	$ 153,119	$ 91,443	$ 613,630	$ 381,088
Operating Netback ($/boe)(2)	$ 45.53	$ 30.44	$ 46.14	$ 32.57
Operating Netback Net of Realized Hedging ($/boe)(2)(3)	$ 44.97	$ 28.71	$ 45.66	$ 29.76
Capital expenditures	$ 92,944	$ 38,752	$ 268,042	$ 139,832
Cash flow from operating activities	$ 158,677	$ 103,196	$ 557,541	$ 305,526
per share - basic	$ 0.30	$ 0.18	$ 1.02	$ 0.52
Adjusted Funds Flow(2)	$ 143,737	$ 81,830	$ 560,935	$ 295,236
per share - basic	$ 0.27	$ 0.14	$ 1.02	$ 0.51
ATHABASCA (THERMAL OIL)				
Bitumen production (bbl/d)(2)	33,849	31,059	33,505	30,246
Petroleum, natural gas and midstream sales	$ 346,716	$ 309,078	$ 1,419,670	$ 1,204,245
Operating Income(2)	$ 143,246	$ 92,199	$ 569,083	$ 370,732
Operating Netback ($/bbl)(2)	$ 46.30	$ 30.78	$ 46.54	$ 32.93
Capital expenditures	$ 74,268	$ 29,371	$ 194,902	$ 118,975
Adjusted Funds Flow(2)	$ 133,398		$ 516,612	
Free Cash Flow(2)	$ 59,130		$ 321,710	
DUVERNAY ENERGY(1)				
Petroleum and natural gas production (boe/d)(2)	3,387	2,068	3,310	4,244
Percentage Liquids (%)(2)	75%	71%	76%	58%
Petroleum, natural gas and midstream sales	$ 20,179	$ 12,659	$ 83,194	$ 91,062
Operating Income(2)	$ 11,776	$ 4,761	$ 51,009	$ 46,291
Operating Netback ($/boe)(2)	$ 37.79	$ 25.02	$ 42.10	$ 29.89
Capital expenditures	$ 18,676	$ 9,381	$ 73,140	$ 20,857
Adjusted Funds Flow(2)	$ 10,339		$ 44,323	
Free Cash Flow(2)	$ (8,337)		$ (28,817)	
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)				
Net income (loss) and comprehensive income (loss)(4)	$ 264,336	$ 27,506	$ 467,743	$ (51,220)
per share - basic(4)	$ 0.50	$ 0.05	$ 0.85	$ (0.09)
per share - diluted(4)	$ 0.50	$ 0.03	$ 0.85	$ (0.09)
COMMON SHARES OUTSTANDING				
Weighted average shares outstanding - basic	526,233,362	574,412,564	547,795,407	583,757,575
Weighted average shares outstanding - diluted	530,796,068	588,498,448	553,382,675	583,757,575

As at ($ Thousands)	December 31, 2024	December 31, 2023
LIQUIDITY AND BALANCE SHEET (CONSOLIDATED)		
Cash and cash equivalents	$ 344,836	$ 343,309
Available credit facilities(5)	$ 136,324	$ 85,488
Face value of term debt(6)	$ 200,000	$ 207,648

(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 $1.9 million and $6.5 million for the three months and year ended December 31, 2024 (three months and year ended December 31, 2023 – loss of $5.5 million and $35.9 million).
(4) Net income (loss) and comprehensive income (loss) per share amounts are based on net income (loss) and comprehensive income (loss) attributable to shareholders of the Parent Company. In the calculation of diluted earnings per share for the three months ended December 31, 2023 earnings were reduced by $11.3 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.
(6) The face value of the term debt at December 31, 2023 was US$157.0 million translated into Canadian dollars at the December 31, 2023 exchange rate of US$1.00 = C$1.3226.

INDEPENDENT RESERVES EVALUATION

The Company's qualified independent reserve evaluators, McDaniel & Associates Consultants Ltd. ("McDaniel"), completed independent reserve evaluations effective December 31, 2024 and 2023. The bitumen reserves are located in Athabasca (Thermal Oil). The light and medium oil, tight oil, shale gas, conventional natural gas, condensate natural gas liquids and other natural gas liquids reserves are located in Duvernay Energy.

Refer to the "Advisories and Other Guidance" section within this MD&A and the Company's AIF dated March 5, 2025, for further details relating to the Company's reserves.

Reserves

At December 31, 2024, the Company had 1,282 MMboe of Proved plus Probable Reserves (December 31, 2023 - 1,243 MMboe).

The following table shows the Company's reserves by segment (tables may not add due to rounding):

	December 31, 2024			December 31, 2023		
Reserves	**Proved Developed Producing**	**Proved**	**Proved plus Probable**	**Proved Developed Producing**	**Proved**	**Proved plus Probable**
Athabasca (Thermal Oil)(1)						
Leismer (MMbbl)	44	332	694	51	331	697
Corner (MMbbl)	—	—	351	—	—	351
Hangingstone (MMbbl)	30	72	163	27	73	167
Total Athabasca (Thermal Oil) (MMbbl)	74	404	1,209	77	404	1,216
Duvernay Energy(2)(3)						
Greater Kaybob (MMboe)	6	41	73	4	11	27
Total Duvernay Energy (MMboe)	6	41	73	4	11	27
Corporate Consolidated reserves (MMboe)(3)	**80**	**445**	**1,282**	**82**	**415**	**1,243**
Corporate Consolidated reserves attributable to:						
Shareholders of the Parent Company (MMboe)	78	433	1,260	82	415	1,243
Non-controlling interest (MMboe)	2	12	22	—	—	—
	80	**445**	**1,282**	**82**	**415**	**1,243**

(1) Athabasca (Thermal Oil) reserves are comprised of bitumen.
(2) Duvernay Energy reserves are comprised of light and medium oil, tight oil, shale gas, conventional natural gas, condensate natural gas liquids and other natural gas liquids.
(3) All reserves presented herein represent Athabasca's and Athabasca's consolidated subsidiaries interest. For illustrative purposes, where indicated, values referred to as "Shareholders of Parent" represent 70% of the value attributable to Duvernay Energy as corresponding to Athabasca's 70% equity interest therein, with the values referred to as "Non-Controlling Interests" reflecting the remainder.

The Athabasca (Thermal Oil) Proved ("1P") and Proved plus Probable ("2P") reserves were consistent year over year at 404 MMbbl and 1,209 MMbbl at December 31, 2024.

The Duvernay Energy 1P reserves increased by 273% to 41 MMbbl at December 31, 2024 and the 2P reserves increased by 170% to 73 MMbbl at December 31, 2024. The increases are primarily attributable to new bookings on 100% working interest operated land acquired in 2023, along with new bookings on 100% working interest operated land acquired from Cenovus Energy as part of the February 6, 2024 Transaction.

BUSINESS ENVIRONMENT

Benchmark prices

(Average)	Three months ended December 31, 2024	2023	Change	Year ended December 31, 2024	2023	Change
Crude oil:						
West Texas Intermediate (WTI) (US$/bbl)[1]	$ 70.27	$ 78.32	(10) %	$ 75.72	$ 77.62	(2) %
West Texas Intermediate (WTI) (C$/bbl)[1]	$ 98.29	$ 106.65	(8) %	$ 103.71	$ 104.73	(1) %
Western Canadian Select (WCS) (C$/bbl)[2]	$ 80.74	$ 76.92	5 %	$ 83.52	$ 79.54	5 %
Edmonton Par (C$/bbl)[3]	$ 94.91	$ 99.71	(5) %	$ 97.57	$ 100.56	(3) %
Edmonton Condensate (C5+) (C$/bbl)[4]	$ 98.25	$ 102.83	(4) %	$ 99.24	$ 102.11	(3) %
WCS Differential:						
to WTI (US$/bbl)	$ (12.56)	$ (21.89)	(43) %	$ (14.76)	$ (18.66)	(21) %
to WTI (C$/bbl)	$ (17.55)	$ (29.73)	(41) %	$ (20.19)	$ (25.19)	(20) %
Edmonton Par Differential:						
to WTI (US$/bbl)	$ (2.42)	$ (5.19)	(53) %	$ (4.51)	$ (3.22)	40 %
to WTI (C$/bbl)	$ (3.38)	$ (6.94)	(51) %	$ (6.14)	$ (4.17)	47 %
Natural gas:						
AECO (C$/GJ)[5][6]	$ 1.40	$ 2.18	(36) %	$ 1.38	$ 2.51	(45) %
Foreign exchange:						
USD : CAD	1.3988	1.3617	3 %	1.3697	1.3493	2 %

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]	33,500-35,500	~4,000	~37,500-39,500
Adjusted Funds Flow[1]	~$475-$500	~$55	~$525-$550
Capital Expenditures	~$250	~$85	~$335
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) Annual price assumptions for March 5, 2025 guidance: US$70 WTI, US$12.50 WCS heavy differential, C$2 AECO, and 0.725 C$/US$ FX.
(3) Duvernay Energy reflects gross production and financial metrics before taking into consideration Athabasca's 70% equity interest in Duvernay Energy. Duvernay Energy capital self-funded with its Adjusted Funds Flow forecast and independent balance sheet.

Athabasca (Thermal Oil)

The Thermal Oil division underpins the Company's strong Free Cash Flow outlook, with unchanged production guidance of 33,500 – 35,500 bbl/d and an unchanged approximately $250 million capital budget. The program at Leismer includes the tie-in of six redrills and four new sustaining well pairs on Pad 10 early in 2025, along with continued pad and facility expansion work for the progressive expansion to 40,000 bbl/d. At Hangingstone two extended reach sustaining well pairs (approximately 1,400 meter average laterals) that were drilled in 2024 will be placed on production in March.

Duvernay Energy

The 2025 capital program of approximately $85 million includes the completion of a 100% working interest ("WI") three-well pad that was drilled in 2024 and the drilling and completion of a 30% WI four-well pad. Activity will also include spudding two additional multi-well pads in the second half of 2025 (one operated 100% WI pad and one 30% WI pad) with completions to follow in 2026. Duvernay Energy is constructing gathering system infrastructure on its operated assets that will support exit production of approximately 5,500 boe/d this year and momentum into 2026.

2024 GUIDANCE REVIEW

The Company's original guidance was updated on December 19, 2023 with the announcement of the Duvernay Energy transaction. Athabasca (Thermal Oil) achieved its annual production guidance that was increased on July 24, 2024 based on the strong operational performance. Cash flow guidance was updated throughout the year to reflect realized commodity prices, the outlook for prices for the balance of the year and underlying operating results. Athabasca (Thermal Oil) achieved its annual capital expenditures guidance that was increased on July 24, 2024 with the sanctioning of a progressive growth program to 40,000 bbl/d at Leismer. Duvernay Energy achieved its annual production guidance. Capital expenditures were below initial guidance primarily due to scope deferral into 2025.

Athabasca (Thermal Oil)

2024 Guidance ($ millions, unless otherwise noted)	Original Guidance Dec 6, 2023	Guidance Updates (Thermal Oil) Dec 19, 2023	Feb 29, 2024	May 8, 2024	Jul 24, 2024	Oct 30, 2024	Actual Full year
Production (boe/d)[1]	35,000-36,000	32,000-33,000	32,000-33,000	32,000-33,000	33,000-34,000	33,000-34,000	33,505
Adjusted Funds Flow[1]	$ 500	$ 460	$ 460	$ 500	$ 540	$ 510	$ 517
Free Cash Flow[1]	$ 325	$ 325	$ 325	$ 365	$ 350	$ 315	$ 322
Capital expenditures	$ 175	$ 135	$ 135	$ 135	$ 193	$ 195	$ 195

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

Duvernay Energy[2]

2024 Guidance ($ millions, unless otherwise noted)	Original Guidance Dec 19, 2023	Guidance Updates (Duvernay Energy) Feb 29, 2024	May 8, 2024	Jul 24, 2024	Oct 30, 2024	Actual Full year
Production (boe/d)[1]	3,000	3,000	3,000	3,000	3,000	3,310
Adjusted Funds Flow[1]	$ 40	$ 50	$ 50	$ 50	$ 45	$ 44
Capital expenditures	$ 82	$ 82	$ 82	$ 82	$ 75	$ 73

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP measures and production disclosure.
(2) Duvernay Energy reflects gross production and financial metrics before taking into consideration Athabasca's 70% equity interest in Duvernay Energy. Duvernay Energy capital program funded by seed capital and Adjusted Funds Flow forecast.

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 December 31, 2024	2023	Year ended December 31, 2024	2023
PRODUCTION				
Bitumen (bbl/d)	33,849	31,059	33,505	30,246
Oil and condensate (bbl/d)(1)	2,103	1,208	2,202	1,924
Natural gas (Mcf/d)(1)	5,172	3,612	4,677	10,769
Other natural gas liquids (bbl/d)(1)	422	258	329	525
Total (boe/d)(1)	37,236	33,127	36,815	34,490

(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 December 31, 2024	2023	Year ended December 31, 2024	2023
Petroleum, natural gas and midstream sales(1)	$ 366,895	$ 321,737	$ 1,502,864	$ 1,295,307
Royalties	(15,166)	(17,875)	(86,099)	(73,448)
Cost of diluent(1)	(137,817)	(137,438)	(549,808)	(518,219)
Operating expenses	(36,954)	(46,427)	(159,973)	(193,882)
Transportation and marketing(2)	(21,936)	(23,037)	(86,892)	(92,735)
Operating Income(3)	155,022	96,960	620,092	417,023
Realized loss on commodity risk mgmt. contracts	(1,903)	(5,517)	(6,462)	(35,935)
OPERATING INCOME NET OF REALIZED HEDGING(3)	$ 153,119	$ 91,443	$ 613,630	$ 381,088
REALIZED PRICES(3)				
Heavy oil (Blended bitumen) ($/bbl)(3)	$ 78.61	$ 72.95	$ 81.92	$ 75.98
Oil and condensate ($/bbl)(3)	94.09	98.29	95.31	98.78
Natural gas ($/Mcf)(3)	1.63	3.00	1.49	3.12
Other natural gas liquids ($/bbl)(3)	31.14	31.07	31.83	49.09
Realized price (net of cost of diluent) ($/boe)(3)	67.27	57.86	70.92	60.69
Royalties ($/boe)(3)	(4.45)	(5.61)	(6.41)	(5.74)
Operating expenses ($/boe)(3)	(10.85)	(14.58)	(11.90)	(15.14)
Transportation and marketing ($/boe)(2)(3)	(6.44)	(7.23)	(6.47)	(7.24)
Operating Netback ($/boe)(3)	45.53	30.44	46.14	32.57
Realized loss on commodity risk mgmt. contracts ($/boe)(3)	(0.56)	(1.73)	(0.48)	(2.81)
OPERATING NETBACK NET OF REALIZED HEDGING ($/boe)(3)	$ 44.97	$ 28.71	$ 45.66	$ 29.76

(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 $2.2 million for the three months and year ended December 31, 2024 (three months and year ended December 31, 2023 - $0.6 million and $2.2 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 December 31, 2024	2023	Year ended December 31, 2024	2023
Athabasca (Thermal Oil)	$ 74,268	$ 29,371	$ 194,902	$ 118,975
Duvernay Energy	18,676	9,381	73,140	20,857
CORPORATE CONSOLIDATED CAPITAL EXPENDITURES(1)(2)(3)	$ 92,944	$ 38,752	$ 268,042	$ 139,832

(1) For the three months and year ended December 31, 2024, expenditures include capitalized cash based stock-based compensation costs of $nil and $0.5 million (three months and year ended December 31, 2023 - $0.1 million and $1.6 million).
(2) For the three months and year ended December 31, 2024 expenditures include capitalized staff costs of $2.4 million and $8.5 million (three months and year ended December 31, 2023 - $1.9 million and $7.6 million).
(3) Excludes non-cash capitalized costs related to stock-based compensation, decommissioning obligation assets and leased asset modifications.

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 significant 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 proven reserves in place to support a flat production profile for approximately 30 years and a reserve life index of approximately 65 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 proven reserves in place to support a flat production profile for approximately 25 years and a reserve life index of approximately 60 years (proved plus probable) at current production levels. Hangingstone has Proved plus Probable Reserves of approximately 163 MMbbl(1).

Royalty

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 December 31, 2024	2023	Year ended December 31, 2024	2023
VOLUMES				
Bitumen production (bbl/d)	26,345	23,764	26,103	22,497
Bitumen sales (bbl/d)	25,919	24,084	26,013	22,816
Heavy oil (blended bitumen) sales (bbl/d)	37,108	34,277	37,005	32,170

($ Thousands, unless otherwise noted)	Three months ended December 31, 2024	2023	Year ended December 31, 2024	2023
Heavy oil (blended bitumen) sales	$ 267,768	$ 229,563	$ 1,100,153	$ 889,825
Cost of diluent	(109,294)	(104,762)	(438,837)	(389,410)
Total bitumen sales	158,474	124,801	661,316	500,415
Royalties	(9,585)	(12,234)	(59,191)	(46,773)
Operating expenses - non-energy	(15,594)	(17,962)	(71,308)	(64,815)
Operating expenses - energy	(7,959)	(11,291)	(33,935)	(50,691)
Transportation and marketing	(12,310)	(12,677)	(49,634)	(50,064)
LEISMER OPERATING INCOME(1)	$ 113,026	$ 70,637	$ 447,248	$ 288,072
REALIZED PRICE(1)				
Heavy oil (blended bitumen) sales ($/bbl)(1)	$ 78.43	$ 72.80	$ 81.23	$ 75.78
Bitumen sales ($/bbl)(1)	$ 66.46	$ 56.33	$ 69.46	$ 60.09
Royalties ($/bbl)(1)	(4.02)	(5.52)	(6.22)	(5.62)
Operating expenses - non-energy ($/bbl)(1)	(6.54)	(8.11)	(7.49)	(7.78)
Operating expenses - energy ($/bbl)(1)	(3.34)	(5.10)	(3.56)	(6.09)
Transportation and marketing ($/bbl)(1)	(5.16)	(5.72)	(5.21)	(6.01)
LEISMER OPERATING NETBACK ($/bbl)(1)	$ 47.40	$ 31.88	$ 46.98	$ 34.59

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

Leismer’s bitumen production for the three months and year ended December 31, 2024 was 26,345 bbl/d and 26,103 bbl/d, an increase of 11% and 16%, respectively, compared to the corresponding periods in 2023. The production increases are attributed to completing the facility expansion mid-year and the ramp-up of new well pairs.

Total operating expenses were $9.88/bbl in the fourth quarter of 2024 and $11.05/bbl in the year ended 2024, compared to $13.21/bbl and $13.87/bbl for the same periods in 2023, respectively. The decrease on a per barrel basis is largely the result of higher production and lower energy costs in 2024.

Leismer’s Operating Netback was $47.40/bbl for fourth quarter 2024 and $46.98/bbl for the year ended December 31, 2024, compared to $31.88/bbl and $34.59/bbl with the same periods in 2023, respectively. The operating netback increase was primarily a result of higher realized heavy oil prices and lower total operating expenses on a per barrel basis.

Hangingstone Operating Results

	Three months ended December 31, 2024	2023	Year ended December 31, 2024	2023
VOLUMES				
Bitumen production (bbl/d)	7,504	7,295	7,402	7,749
Bitumen sales (bbl/d)	7,709	8,468	7,392	8,020
Heavy oil (blended bitumen) sales (bbl/d)	10,836	11,777	10,342	11,251

($ Thousands, unless otherwise noted)	Three months ended December 31, 2024	2023	Year ended December 31, 2024	2023
Heavy oil (blended bitumen) and midstream sales	$ 78,948	$ 79,515	$ 319,517	$ 314,420
Cost of diluent	(28,523)	(32,676)	(110,971)	(128,809)
Total bitumen and midstream sales	50,425	46,839	208,546	185,611
Royalties	(2,828)	(3,461)	(15,873)	(14,092)
Operating expenses - non-energy	(5,105)	(5,805)	(21,836)	(22,301)
Operating expenses - energy	(3,567)	(6,360)	(15,778)	(31,078)
Transportation and marketing(1)	(8,705)	(9,651)	(33,224)	(35,480)
HANGINGSTONE OPERATING INCOME(2)	$ 30,220	$ 21,562	$ 121,835	$ 82,660
REALIZED PRICE(2)				
Heavy oil (blended bitumen) and midstream sales ($/bbl)(2)	$ 79.19	$ 73.39	$ 84.41	$ 76.56
Bitumen and midstream sales ($/bbl)(2)	$ 71.10	$ 60.12	$ 77.08	$ 63.41
Royalties ($/bbl)(2)	(3.99)	(4.44)	(5.87)	(4.81)
Operating expenses - non-energy ($/bbl)(2)	(7.20)	(7.45)	(8.07)	(7.62)
Operating expenses - energy ($/bbl)(2)	(5.03)	(8.16)	(5.83)	(10.62)
Transportation and marketing ($/bbl)(1)(2)	(12.27)	(12.39)	(12.28)	(12.12)
HANGINGSTONE OPERATING NETBACK ($/bbl)(2)	$ 42.61	$ 27.68	$ 45.03	$ 28.24

(1) Transportation and marketing excludes non-cash costs of $0.6 million and $2.2 million for the three months and year ended December 31, 2024 (three months and year ended December 31, 2023 - $0.6 million and $2.2 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.

Average Hangingstone bitumen production for the year ended December 31, 2024 decreased modestly (4%) compared to the same period in 2023 primarily as a result of natural declines.

Total operating expenses were $12.23/bbl in the fourth quarter of 2024 and $13.90/bbl in the year ended 2024, compared to $15.61/bbl and $18.24/bbl for the same periods in 2023, respectively. The decrease on a per barrel basis is the result of lower energy costs in 2024.

Hangingstone’s Operating Netback was $42.61/bbl for the fourth quarter 2024, compared to $27.68/bbl with the same period in 2023. The increase is primarily a result of higher realized oil prices and lower energy operating expenses. The Operating Netback was $45.03/bbl for the year ended December 31, 2024, compared to $28.24/bbl with the same period in 2023. The increase is primarily a result of higher realized oil prices and lower energy operating expenses, partially offset by higher royalties.

Athabasca (Thermal Oil) Operating Results

	Three months ended December 31, 2024	2023	Year ended December 31, 2024	2023
VOLUMES				
Bitumen production (bbl/d)	33,849	31,059	33,505	30,246
Bitumen sales (bbl/d)	33,628	32,552	33,405	30,836
Heavy oil (blended bitumen) sales (bbl/d)	47,944	46,054	47,347	43,421

($ Thousands, unless otherwise noted)	Three months ended December 31, 2024	2023	Year ended December 31, 2024	2023
Heavy oil (blended bitumen) and midstream sales	$ 346,716	$ 309,078	$ 1,419,670	$ 1,204,245
Cost of diluent	(137,817)	(137,438)	(549,808)	(518,219)
Total bitumen and midstream sales	208,899	171,640	869,862	686,026
Royalties	(12,413)	(15,695)	(75,064)	(60,865)
Operating expenses - non-energy	(20,699)	(23,767)	(93,144)	(87,116)
Operating expenses - energy	(11,526)	(17,651)	(49,713)	(81,769)
Transportation and marketing(1)	(21,015)	(22,328)	(82,858)	(85,544)
ATHABASCA (THERMAL OIL) OPERATING INCOME(2)	$ 143,246	$ 92,199	$ 569,083	$ 370,732
REALIZED PRICE(2)				
Heavy oil (blended bitumen) and midstream sales ($/bbl)(2)	$ 78.61	$ 72.95	$ 81.92	$ 75.98
Bitumen and midstream sales ($/bbl)(2)	$ 67.52	$ 57.31	$ 71.15	$ 60.95
Royalties ($/bbl)(2)	(4.01)	(5.24)	(6.14)	(5.41)
Operating expenses - non-energy ($/bbl)(2)	(6.69)	(7.94)	(7.62)	(7.74)
Operating expenses - energy ($/bbl)(2)	(3.73)	(5.89)	(4.07)	(7.27)
Transportation and marketing ($/bbl)(1)(2)	(6.79)	(7.46)	(6.78)	(7.60)
ATHABASCA (THERMAL OIL) OPERATING NETBACK ($/bbl)(2)	$ 46.30	$ 30.78	$ 46.54	$ 32.93

(1) Transportation and marketing excludes non-cash costs of $0.6 million and $2.2 million for the three months and year ended December 31, 2024 (three months and year ended December 31, 2023 - $0.6 million and $2.2 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 December 31, 2024	2023	Year ended December 31, 2024	2023
Leismer Project	$ 71,026	$ 24,999	$ 163,794	$ 99,007
Hangingstone Project	2,993	4,026	28,446	13,351
Other	249	346	2,662	6,617
ATHABASCA (THERMAL OIL) CAPITAL EXPENDITURES(1)	$ 74,268	$ 29,371	$ 194,902	$ 118,975

(1) For the three months and year ended December 31, 2024, capital expenditures include $1.7 million and $6.4 million of capitalized staff costs (three months and year ended December 31, 2023 - $1.5 million and $6.0 million).

Thermal Oil capital expenditures for the year ended December 31, 2024 of $194.9 million were primarily focused at Leismer. At Leismer, the Company completed the facility expansion project that supported growth to approximately 28,000 bbl/d in 2024 and commenced the progressive growth program to 40,000 bbl/d. Capital expenditures included further development of Pad 8 (four additional well pairs), three redrills on Pad 4, the tie-in of four infill wells on Pad 7, completions operations of four well pairs at Pad 10, six redrills on Pad 1 and the commencement of construction at Pad 11. At Hangingstone, the Company completed the drilling and completion of two sustaining well pairs on Pad AA that commenced steaming in the fourth quarter of 2024 and first production is expected in early 2025.

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 December 31, 2024	2023	Year ended December 31, 2024	2023
PRODUCTION[1]				
Oil and condensate (bbl/d)	2,103	1,208	2,202	1,924
Natural gas (Mcf/d)	5,172	3,612	4,677	10,769
Other natural gas liquids (bbl/d)	422	258	329	525
Total (boe/d)	3,387	2,068	3,310	4,244
% Liquids	75%	71%	76%	58%

(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 December 31, 2024	2023	Year ended December 31, 2024	2023
Petroleum and natural gas sales	$ 20,179	$ 12,659	$ 83,194	$ 91,062
Royalties	(2,753)	(2,180)	(11,035)	(12,583)
Operating expenses	(4,729)	(5,009)	(17,116)	(24,997)
Transportation and marketing	(921)	(709)	(4,034)	(7,191)
DUVERNAY ENERGY OPERATING INCOME[1]	$ 11,776	$ 4,761	$ 51,009	$ 46,291
REALIZED PRICES[1]				
Oil and condensate ($/bbl)[1]	$ 94.09	$ 98.29	$ 95.31	$ 98.78
Natural gas ($/Mcf)[1]	1.63	3.00	1.49	3.12
Other natural gas liquids ($/bbl)[1]	31.14	31.07	31.83	49.09
Realized price ($/boe)[1]	64.76	66.54	68.67	58.79
Royalties ($/boe)[1]	(8.83)	(11.46)	(9.11)	(8.12)
Operating expenses ($/boe)[1]	(15.18)	(26.33)	(14.13)	(16.14)
Transportation and marketing ($/boe)[1]	(2.96)	(3.73)	(3.33)	(4.64)
DUVERNAY ENERGY OPERATING NETBACK ($/boe)[1]	$ 37.79	$ 25.02	$ 42.10	$ 29.89

(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 months ended December 31, 2024 increased over the respective period in 2023 primarily due to the new production from five gross (2.9 net) wells that were placed on production in the second quarter of 2024. Production for the year ended December 31, 2024 decreased over the respective period in 2023 primarily due to the closing of the Light Oil Non-Core Asset Sale later in the third quarter of 2023.

For the three months ended December 31, 2024 the Operating Netback was $37.79/boe, the increase from the comparable 2023 period is primarily due to a decrease in royalties and operating expenses. The Operating Netback was $42.10/boe for the year ended December 31, 2024, the increase from the comparable 2023 period is primarily due to higher realized prices and a decrease in operating expenses.

Duvernay Energy Capital Expenditures

($ Thousands)	Three months ended December 31, 2024	2023	Year ended December 31, 2024	2023
DUVERNAY ENERGY CAPITAL EXPENDITURES[1]	$ 18,676	$ 9,381	$ 73,140	$ 20,857

(1) For the three months and year ended December 31, 2024, capital expenditures include $0.7 million and $2.1 million of capitalized staff costs (three months and year ended December 31, 2023 - $0.4 million and $1.6 million).

For the year ended December 31, 2024, Duvernay Energy's capital expenditures of $73.1 million were focused on drilling and completions on a two well pad (100% working interest) and drilling and completions on a three well pad (30% working interest), which were both placed on production in the second quarter of 2024. Capital expenditures in the period also included drilling a three well pad (100% working interest) that is expected to be completed and placed on production in 2025 and preliminary work on the pipeline connecting the Duvernay Energy south lands to the Kaybob East Facility.

CORPORATE REVIEW

Liquidity and Capital Resources

Funding

For 2025, Athabasca's capital and operating activities will be funded through cash flow from operating activities and existing cash and cash equivalents. The Company is directing forecasted Free Cash Flow in 2025 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 December 31, 2024, Athabasca had Liquidity of $481.2 million which included $344.8 million of cash and cash equivalents (comprised of $318.9 million Athabasca (Thermal Oil) and $25.9 million Duvernay Energy) and $136.4 million of available capacity on its credit facilities (comprised of $87.5 million Athabasca (Thermal Oil) and $48.9 million Duvernay Energy).

Indebtedness

Athabasca had the following debt instruments and credit facilities in place as at December 31, 2024:

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 new $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 December 31, 2024, 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, 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 May 31, 2026. The Credit Facility is subject to a semi-annual borrowing base review, occurring by May 31 and November 30 of each year. In the fourth quarter of 2024, the semi-annual borrowing base review was completed and the borrowing base was confirmed at $110.0 million. 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 December 31, 2024, the Company had no amounts drawn and $41.1 million of letters of credit outstanding under the Credit Facility. As at December 31, 2023, the Company had no amounts drawn and $27.1 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 December 31, 2024, the Company had $56.4 million of letters of credit outstanding under the Unsecured Letter of Credit Facility (December 31, 2023 - $57.5 million).

Duvernay Energy Credit Facility

Duvernay Energy has a $50.0 million reserve-based credit facility (the "Credit Facility"). The 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 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 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 December 31, 2024	2023	Year ended December 31, 2024	2023
Financing and interest expense on indebtedness	$ 4,599	$ 6,072	$ 22,553	$ 25,272
2026 Notes redemption premium	—	—	12,530	1,376
Accretion and loss on extinguishment of 2026 Notes	—	1,923	27,942	3,155
Accretion of 2029 Notes	191	—	295	—
Accretion of warrants	—	415	187	1,013
Accretion of provisions	2,058	1,911	7,950	7,780
Interest expense on lease liability	86	127	405	588
TOTAL FINANCING AND INTEREST	$ 6,934	$ 10,448	$ 71,862	$ 39,184

For the years ended December 31, 2024 and 2023, financing and interest expense on indebtedness were primarily attributable to the Company's 2026 Notes. On August 9, 2024 the Company redeemed the 2026 Notes and paid a term debt redemption premium of $12.5 million. As a result of the early redemption of the 2026 Notes a $23.2 million loss on extinguishment was expensed for the year ended December 31, 2024.

Foreign Exchange Gain (Loss), Net

($ Thousands)	Three months ended December 31, 2024	2023	Year ended December 31, 2024	2023
Unrealized foreign exchange gain (loss)	$ 15,390	$ (3,267)	$ 39,010	$ (1,141)
Realized foreign exchange gain (loss)	5,270	(1,153)	(16,790)	(1,293)
FOREIGN EXCHANGE GAIN (LOSS), NET	$ 20,660	$ (4,420)	$ 22,220	$ (2,434)

The unrealized foreign exchange gain (loss) primarily relates to the principal and interest components of the Company's US dollar denominated 2026 Notes and US denominated cash. The realized foreign exchange loss for year ended December 31, 2024 includes a $21.6 million realized foreign exchange loss on the US dollar denominated 2026 Notes redeemed on August 9, 2024.

The Company is also exposed to foreign currency risk on oil sales based on US dollar benchmark prices.

Risk Management Contracts

Under the Company's commodity risk management program, Athabasca 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), Athabasca 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

As at December 31, 2024, the following financial commodity risk management contracts were in place:

Instrument	Period	Volume		C$ Average Price(1)		US$ Average Price(1)
Sales contracts				*C$/bbl*		*US$/bbl*
WCS fixed price swaps	January - March 2025	12,000 bbl/d	$	19.25	$	13.38
Purchase contracts				*C$/GJ*		*US$/GJ*
AECO fixed price swaps	January - December 2025	27,000 GJ/d	$	2.02	$	1.40

(1) The implied C$ or US$ Average Price per bbl or GJ, as applicable, was calculated using the December 31, 2024 exchange rate of US$1.00 = C$1.4389.

In 2021, Athabasca entered into a seven-year marketing agreement for 15,000 bbl/d 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 December 31, 2024, the pricing derivative had an asset value of $3.3 million (December 31, 2023 - asset value of $2.0 million).

The following table summarizes the Company's net gain (loss) on commodity risk management contracts for the three months and year ended December 31, 2024 and 2023:

($ Thousands)	Three months ended December 31, 2024	2023	Year ended December 31, 2024	2023
Unrealized gain (loss) on commodity risk mgmt. contracts	$ 6,080	$ 1,435	$ 4,597	$ 6,390
Realized loss on commodity risk mgmt. contracts	(1,903)	(5,517)	(6,462)	(35,935)
GAIN (LOSS) ON COMMODITY RISK MGMT. CONTRACTS, NET	$ 4,177	$ (4,082)	$ (1,865)	$ (29,545)

The following table summarizes the sensitivity to price changes for Athabasca's commodity risk management contracts as at December 31, 2024:

As at December 31, 2024	Change in WCS differential Increase of US$1.00/bbl	Decrease of US$1.00/bbl	Change in AECO Increase of C$1.00/GJ	Decrease of C$1.00/GJ
Increase (decrease) to fair value of commodity risk management contracts	$ 1,556	$ (1,526)	$ 9,627	$ (9,627)

Commitments

The following table summarizes Athabasca's estimated future unrecognized minimum commitments as at December 31, 2024 for the following five years and thereafter:

($ Thousands)	2025	2026	2027	2028	2029	Thereafter	Total
Transportation and processing(1)	$ 113,214	$ 120,668	$ 149,824	$ 131,310	$ 120,220	$ 1,696,128	$ 2,331,364
Interest expense on term debt	13,500	13,500	13,500	13,500	7,875	—	61,875
Purchase commitments and other(1)	15,816	2,200	—	—	—	—	18,016
TOTAL COMMITMENTS	$ 142,530	$ 136,368	$ 163,324	$ 144,810	$ 128,095	$ 1,696,128	$ 2,411,255

(1) Commitments which are denominated in US dollars were translated into Canadian dollars at the December 31, 2024 exchange rate of US$1.00 = C$1.4389.

At December 31, 2024, Athabasca's commitments included new agreements or amended existing agreements resulting in additional net commitments of $0.9 billion compared to December 31, 2023, related to the progressive growth program at Leismer to 40,000 bbl/d.

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 December 31, 2024. 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 interest earned on its floating rate cash and cash equivalents balance at December 31, 2024 of $344.8 million (December 31, 2023 - $343.3 million). A 1.0% change in interest rates would have an annualized impact of approximately $3.4 million (year ended December 31, 2023 - $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.

Other Corporate Items

General and Administrative ("G&A")

($ Thousands, unless otherwise noted)	Three months ended December 31, 2024	2023	Year ended December 31, 2024	2023
TOTAL GENERAL AND ADMINISTRATIVE	$ 5,739	$ 6,285	$ 22,248	$ 20,646
G&A per boe[1]	$ 1.68	$ 2.06	$ 1.65	$ 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 months and year ended December 31, 2024, Athabasca's stock-based compensation expense was $8.9 million and $30.5 million, respectively, compared to $1.8 million and $54.2 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 quarters.

Depletion and Depreciation

For the three months and year ended December 31, 2024, Athabasca's depletion and depreciation expense was $30.1 million and $115.1 million compared to $24.5 million and $110.8 million in the respective prior year periods. The year over year increase in depletion expense primarily relates to the addition of new wells at Leismer and Duvernay, partially offset by natural declines at Hangingstone and the closing of the Light Oil Non-Core Asset Sale in the third quarter of 2023.

Impairment Reversal

In the fourth quarter of 2024, Athabasca identified indicators of impairment reversal within the Hangingstone CGU related to the operating performance of the CGU in conjunction with the current commodity price environment. As a result, the Company completed an impairment test on its Hangingstone CGU which resulted in an estimated recoverable value of $536 million, which was above the CGU's carrying value of $318 million, resulting in an impairment reversal of $218 million at December 31, 2024. At December 31, 2023, no indicators of impairment or impairment reversal were identified.

Gain (Loss) on Revaluation of Provisions and Other

($ Thousands)	Three months ended December 31, 2024	2023	Year ended December 31, 2024	2023
Change in fair value of warrant liability	$ (3,451)	$ 11,725	$ (7,224)	$ (25,801)
Change in estimated decommissioning obligations related to fully impaired assets	(244)	(94)	(5,918)	(94)
GAIN (LOSS) ON REVALUATION OF PROVISIONS AND OTHER	$ (3,695)	$ 11,631	$ (13,142)	$ (25,895)

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 2023 and 2024 primarily relate to changes in the share price.

Income Taxes

For the year ended 2024, as a result of income before income tax of $617.3 million, $145.3 million of income tax expense was recorded (year ended 2023 - $14.1 million). At December 31, 2024, the Company recognized a deferred tax asset of $307.3 million (December 31, 2023 - $403.5 million), a current income tax payable of $2.7 million (December 31, 2023 - nil) and a deferred tax liability of $42.6 million (December 31, 2023 - nil). The liabilities are recognized as a result of the assets transferred in the Duvernay Energy Transaction. The Company has approximately $2.3 billion in tax pools, including approximately $1.8 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 December 31, 2024, there were 517.6 million common shares outstanding, an aggregate of 7.6 million restricted share units and performance share units outstanding, 2.7 million stock options outstanding and 6.7 million potential shares issuable under warrants agreements (29,324 warrants outstanding).

In the first quarter of 2024, the Company renewed its NCIB with approval to purchase up to 55.4 million common shares during the twelve-month period commencing on March 18, 2024 and ending March 17, 2025. The Company fully completed its previous NCIB and purchased and cancelled a total of 58.0 million common shares for the twelve-month period ended March 15, 2024.

During the year ended 2024, the Company repurchased for cancellation 61.3 million common shares under its NCIB program. Subsequent to December 31, 2024, the Company repurchased for cancellation 4.3 million common shares under its NCIB program.

As at March 5, 2025, there were 513.3 million common shares outstanding, an aggregate of 7.6 million restricted share units and performance share units outstanding, 2.7 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:

	2024				2023			
($ Thousands, unless otherwise noted)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	70.27	75.09	80.57	76.96	78.32	82.26	73.78	76.13
WTI (C$/bbl)	98.29	102.39	110.25	103.80	106.65	110.29	99.09	102.92
Western Canadian Select (C$/bbl)	80.74	83.91	91.59	77.73	76.92	93.00	78.80	69.42
Edmonton Par (C$/bbl)	94.91	97.85	105.32	92.21	99.71	107.85	95.33	99.34
Edmonton Condensate (C5+) (C$/bbl)	98.25	96.49	104.85	97.36	102.83	104.05	96.10	105.44
AECO (C$/GJ)	1.40	0.65	1.12	2.36	2.18	2.46	2.32	3.05
Foreign exchange (USD : CAD)	1.40	1.36	1.37	1.35	1.36	1.34	1.34	1.35
CORPORATE CONSOLIDATED(1)								
Petroleum and natural gas production (boe/d)(2)	37,236	38,909	37,621	33,470	33,127	36,176	33,971	34,683
Realized price (net of cost of diluent) ($/boe)(2)	67.27	72.90	79.93	62.18	57.86	80.85	59.25	44.74
Petroleum, natural gas and midstream sales ($)(3)	366,895	397,362	422,028	316,579	321,737	385,269	289,310	298,991
Operating Income ($)(2)	155,022	180,184	179,751	105,135	96,960	168,410	95,118	56,535
Operating Income Net of Realized Hedging ($)(2)	153,119	175,755	178,176	106,580	91,443	164,643	90,522	34,480
Operating Netback ($/boe)(2)	45.53	49.12	52.46	35.78	30.44	50.84	32.23	16.85
Operating Netback Net of Realized Hedging ($/boe)(2)	44.97	47.91	52.00	36.27	28.71	49.70	30.67	10.27
Capital expenditures ($)	92,944	50,634	48,453	76,011	38,752	33,286	41,432	26,362
Cash flow from operating activities ($)	158,677	187,143	135,083	76,638	103,196	134,879	46,914	20,537
Adjusted Funds Flow ($)(2)	143,737	163,680	165,746	87,772	81,830	141,138	81,664	(9,396)
ATHABASCA (THERMAL OIL)								
Bitumen production (bbl/d)	33,849	34,853	33,765	31,536	31,059	31,691	29,016	29,179
Bitumen sales volumes (bbl/d)	33,628	35,813	33,794	30,358	32,552	31,527	27,482	31,765
Realized bitumen price ($/bbl)(2)	67.52	73.65	80.36	61.96	57.31	83.90	60.33	42.03
Heavy Oil (blended bitumen) and midstream sales ($)	346,716	372,634	395,279	305,041	309,078	360,761	265,304	269,102
Operating Income ($)(2)	143,246	163,694	161,694	100,449	92,199	155,415	81,621	41,497
Operating Netback ($/bbl)(2)	46.30	49.68	52.59	36.36	30.78	53.59	32.64	14.52
Capital expenditures ($)	74,268	44,431	34,084	42,119	29,371	34,439	30,679	24,486
Adjusted Funds Flow ($)(2)	133,398	150,088	149,413	83,713				
Free Cash Flow ($)(2)	59,130	105,657	115,329	41,594				
DUVERNAY ENERGY(1)								
Petroleum and natural gas production (boe/d)(2)	3,387	4,056	3,856	1,934	2,068	4,485	4,955	5,504
Realized price ($/boe)(2)	64.76	66.27	76.23	65.56	66.54	59.40	53.24	60.34
Petroleum and natural gas sales ($)(3)	20,179	24,728	26,749	11,538	12,659	24,508	24,006	29,889
Operating Income ($)(2)	11,776	16,490	18,057	4,686	4,761	12,995	13,497	15,038
Operating Netback ($/boe)(2)	37.79	44.20	51.46	26.63	25.02	31.50	29.92	30.35
Capital expenditures ($)	18,676	6,203	14,369	33,892	9,381	(1,153)	10,753	1,876
Adjusted Funds Flow ($)(2)	10,339	13,592	16,333	4,059				
Free Cash Flow ($)(2)	(8,337)	7,389	1,964	(29,833)				
OPERATING RESULTS								
Net income (loss) ($)(4)	264,336	68,722	96,076	38,609	27,506	(79,212)	57,121	(56,635)
Net income (loss) per share - basic ($)(4)	0.50	0.13	0.17	0.07	0.05	(0.14)	0.10	(0.10)
BALANCE SHEET ITEMS								
Cash and cash equivalents ($)	344,836	334,851	303,360	306,503	343,309	337,125	132,491	173,280
Total assets ($)	2,474,609	2,234,651	2,230,648	2,208,094	2,048,635	2,102,338	2,162,091	2,210,487
Term debt ($)(5)	195,833	195,642	190,986	186,773	179,705	182,398	181,577	184,509
Shareholders' equity ($)	1,863,732	1,674,942	1,687,741	1,665,552	1,583,453	1,580,312	1,682,906	1,655,044

(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 (loss) per share amounts are based on net income (loss) attributable to shareholders of the Parent Company.
(5) Balances include the current and long-term portions as reported in the consolidated balance sheets.

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.

SELECTED ANNUAL INFORMATION

The following table provides a summary of selected annual information for the years ended 2024, 2023, and 2022:

($ Thousands, unless otherwise noted)	December 31, 2024	December 31, 2023	December 31, 2022
Petroleum and natural gas production (boe/d)[1]	36,815	34,490	35,262
Petroleum, natural gas and midstream sales	$ 1,442,091	$ 1,268,525	$ 1,504,685
Net income (loss) and comprehensive income (loss)	$ 467,743	$ (51,220)	$ 572,271
per share (basic)[2]	$ 0.85	$ (0.09)	$ 1.01
Cash flow from operating activities	$ 557,541	$ 305,526	$ 315,618
per share (basic)	$ 1.02	$ 0.52	$ 0.56
Adjusted Funds Flow[1]	$ 560,935	$ 295,236	$ 308,004
per share (basic)	$ 1.02	$ 0.51	$ 0.54
Free Cash Flow[1]	$ 292,893	$ 155,404	$ 160,555
Capital expenditures	$ 268,042	$ 139,832	$ 147,449
Total assets	$ 2,474,609	$ 2,048,635	$ 2,230,354
Face value of term debt[3]	$ 200,000	$ 207,648	$ 237,231
Weighted average shares outstanding (basic)	547,795,407	583,757,575	568,035,589
Weighted average shares outstanding (diluted)	553,382,675	583,757,575	586,913,328
Ending shares outstanding (basic)	517,580,684	572,352,204	586,489,001

(1) Refer to the “Advisories and Other Guidance” section within this MD&A for additional information on Non-GAAP Financial Measures and production disclosure.
(2) Net income (loss) and comprehensive income (loss) per share amounts are based on net income (loss) and comprehensive income (loss) attributable to shareholders of the Parent Company.
(3) The face value of the 2029 Notes at December 31, 2024 is $200 million. The face value of the 2026 Notes at December 31, 2024 is nil (December 31, 2023 - US$157 million; December 31, 2022 - US$175 million). 2026 Notes were translated into Canadian dollars at the December 31, 2023 exchange rate of US$1.00 = C$1.3226; December 31, 2022 - US$1.00 = C$1.3544.

ACCOUNTING POLICIES AND ESTIMATES

During the year ended December 31, 2024, 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, except as disclosed in Note 3 of the Consolidated Financial Statements. A summary of the material accounting policy information, including the use of estimates and judgments, used by Athabasca can also be found in Note 3 of the 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).

Material Accounting Estimates and Judgments

The preparation of the Consolidated Financial Statements requires management to use estimates, judgments and assumptions. These judgments and assumptions affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the applicable reporting period. These estimates relate to unsettled transactions and events as of the date of the Consolidated Financial Statements and may differ from actual results as future confirming events occur. Estimates and underlying assumptions are reviewed by management on an ongoing basis. Revisions to accounting estimates are recognized prospectively in the year in which the estimates are revised. Changes in the Company’s accounting estimates and judgments could have a significant impact on net income (loss) and comprehensive income (loss).

Included in the carrying value of property, plant and equipment ("PP&E") are accumulated depletion, depreciation and impairment charges/reversals that are determined, in part, by utilizing estimates based on Athabasca's reserves, resources, relevant market transactions and land acreage values. The estimates of reserves and resources include estimates of the recoverable volumes of bitumen, light crude oil and medium crude oil, tight oil, conventional natural gas, shale gas and Natural Gas Liquids (“NGLs”), future commodity prices and future costs required to develop and produce the assets. Reserve and resource estimates and future cash flows could be revised either upwards or downwards based on updated information from drilling and operating results as well as changes to future commodity price estimates, changes in cost estimates and changes to the anticipated timing of project development. The rates used to discount future cash flows are based on judgment of economic, regulatory and operating factors. Changes in these factors could increase or decrease the discount rate which may result in material changes to the estimated recoverable amount of the assets. Exploration and evaluation assets ("E&E") require judgment as to whether future economic benefits exist, including the estimated recoverability of reserves and contingent resources, technology uncertainty, government regulation uncertainty and the ability to finance exploration and evaluation projects, where technical feasibility and commercial viability has not yet been determined.

For purposes of impairment testing, PP&E and E&E are aggregated into cash-generating units ("CGUs") based on separately identifiable and largely independent cash inflows. The determination of the Company's CGUs is subject to judgment. Factors considered in the classification of CGUs include the integration between assets, shared infrastructures, the existence of common sales points, geography, geologic structure and the manner in which management monitors and makes decisions regarding operations. CGUs are not larger than an operating segment. Impairment test calculations require the use of estimates and assumptions and are subject to change as new information becomes available. Factors that are subject to change include estimates of future commodity prices, expected production volumes, development timing, land values, tax pools, directly comparable market transactions, quantity of reserves and resources, discount rates, recovery rates, timing of anticipated ramp-up of production, and future development, regulatory, carbon and operating costs. Changes in assumptions used in determining the recoverable amount could have a prospective material effect on the carrying value of the related PP&E and E&E CGUs.

The provision for decommissioning obligations is based upon numerous assumptions including the ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. Actual costs and cash outflows could differ from the estimates as a result of changes in any of the above noted assumptions.

Deferred tax assets are recognized only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse and a judgment as to whether or not there will be sufficient taxable profits available to offset the tax assets when they do reverse. This requires assumptions regarding future profitability and is therefore inherently uncertain. To the extent assumptions regarding future profitability change, there can be an increase or decrease in the amounts recognized in respect of deferred tax assets as well as the amounts recognized in net income (loss) and comprehensive income (loss) in the period in which the change occurs. The Company recognizes a deferred tax liability for a tax filing position based on its assessment of the probability that additional taxes may ultimately be due. Tax provisions are based on enacted or substantively enacted laws. Changes in those laws could affect amounts recognized in net income (loss) and comprehensive income (loss) both in the period of change, which would include any impact on cumulative provisions, and in future periods. Income tax filings are subject to audits and re-assessments and changes in facts, circumstances and interpretations of the standards which may result in a material increase or decrease in the Company's provision for income taxes.

Athabasca uses forward commodity price curves as an input in assessing the value of its assets. Refer to Note 9 "Impairment" of the December 31, 2024 audited Consolidated Financial Statements.

All of these 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:

	Three months ended December 31, 2024			Three months ended December 31, 2023
($ Thousands)	Athabasca (Thermal Oil)	Duvernay Energy[1]	Corporate Consolidated[1]	Corporate Consolidated
Cash flow from operating activities	$ 144,810	$ 13,867	$ 158,677	$ 103,196
Changes in non-cash working capital	(11,504)	(3,675)	(15,179)	(21,973)
Settlement of provisions	92	147	239	607
ADJUSTED FUNDS FLOW	133,398	10,339	143,737	81,830
Capital expenditures	(74,268)	(18,676)	(92,944)	(38,752)
FREE CASH FLOW	$ 59,130	$ (8,337)	$ 50,793	$ 43,078

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

	Year ended December 31, 2024			Year ended December 31, 2023
($ Thousands)	Athabasca (Thermal Oil)	Duvernay Energy[1]	Corporate Consolidated[1]	Corporate Consolidated
Cash flow from operating activities	$ 511,828	$ 45,713	$ 557,541	$ 305,526
Changes in non-cash working capital	3,056	(1,541)	1,515	525
Settlement of provisions	1,728	151	1,879	1,762
Long-term deposit	—	—	—	(12,577)
ADJUSTED FUNDS FLOW	516,612	44,323	560,935	295,236
Capital expenditures	(194,902)	(73,140)	(268,042)	(139,832)
FREE CASH FLOW	$ 321,710	$ (28,817)	$ 292,893	$ 155,404

(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 December 31,		Year ended December 31,	
Production		**2024**	**2023**	**2024**	**2023**
Duvernay Energy:					
Oil[1]	bbl/d	2,103	1,208	2,202	1,396
Condensate NGLs	bbl/d	—	—	—	528
Oil and condensate NGLs	bbl/d	2,103	1,208	2,202	1,924
Other NGLs	bbl/d	422	258	329	525
Natural gas[2]	mcf/d	5,172	3,612	4,677	10,769
Total Duvernay Energy	boe/d	3,387	2,068	3,310	4,244
Total Thermal Oil bitumen	bbl/d	33,849	31,059	33,505	30,246
Total Company production	boe/d	37,236	33,127	36,815	34,490

(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 December 31,		Year ended December 31,	
Liquids:		**2024**	**2023**	**2024**	**2023**
Total Duvernay Energy:					
Oil and condensate NGLs	bbl/d	2,103	1,208	2,202	1,924
Other NGLs	bbl/d	422	258	329	525
Total Duvernay Energy Liquids	bbl/d	2,525	1,466	2,531	2,449
as % of Duvernay Energy production		75%	71%	76%	58%
Total Company:					
Total Duvernay Energy Liquids	bbl/d	2,525	1,466	2,531	2,449
Total Thermal Oil bitumen	bbl/d	33,849	31,059	33,505	30,246
Total Company Liquids	bbl/d	36,374	32,525	36,036	32,695
as % of Company production		98%	98%	98%	95%

This MD&A also makes reference to Athabasca's forecasted total average daily Thermal Oil production of approximately 33,500 - 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 4,000 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").

Disclosure controls and procedures ("DC&P") are designed to provide reasonable assurance that the information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under the applicable Canadian securities regulatory requirements.

Part 1 of NI 52-109 defines DC&P as "Controls and other procedures of an issuer that are designed to provide reasonable assurance that information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by an issuer in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the issuer's management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure".

For the year ended December 31, 2024, an evaluation was carried out under the supervision of and with the participation of Athabasca's management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of the Company's DC&P. Based upon that evaluation, the Chief Executive Officer and the Chief Financial Officer of the Company concluded that the design and operation of the Company's DC&P were effective to ensure that the information required by Canadian securities regulatory authorities, will be recorded, processed, summarized and reported within the prescribed timelines.

Management's Report on Internal Controls Over Financial Reporting

Management of Athabasca is responsible for establishing and maintaining adequate "internal control over financial reporting" as such term is defined in the applicable Canadian securities regulations. The Company's policies and procedures regarding internal controls over financial reporting were designed by the Company's management, with the oversight of the Chief Executive Officer and the Chief Financial Officer, to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of the Company's financial statements in accordance with IFRS.

The Company has policies and procedures with respect to internal control over financial reporting that:

- pertain to the maintenance of records, to ensure that dispositions of assets and other material transactions involving the Company are accurately and fairly reflected in a reasonable level of detail in the Company's records;
- provide reasonable assurance that transactions are recorded as necessary to ensure that the preparation of the financial statements is done in accordance with IFRS; and
- provide reasonable assurance regarding the timely detection and prevention of unauthorized acquisitions, uses or dispositions of the Company's assets which could have a material impact on the Company and its financial statements.

Athabasca's policies and procedures regarding internal control over financial reporting may not detect or prevent all inaccuracies, omissions or misstatements. A control system, no matter how well conceived or operated, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with the Company's policies and procedures.

Management, including the Chief Executive Officer and Chief Financial Officer, must assess the effectiveness of the Company's internal control over financial reporting as of December 31, 2024, based on the Internal Control - Integrated Framework (the "Framework") established by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In making its assessment, Management used the COSO 2013 Framework in order to evaluate the design and effectiveness of internal control over financial reporting. Based upon management's assessment, the Company has maintained effective internal control over financial reporting as of December 31, 2024.

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