Management's Discussion and Analysis

Q2 2023

ATHABASCA OIL CORPORATION

This Management's Discussion and Analysis of the financial condition and results of operations ("MD&A") of Athabasca Oil Corporation ("Athabasca" or the "Company") is dated July 26, 2023 and should be read in conjunction with the unaudited condensed interim consolidated financial statements ("Consolidated Financial Statements") as at and for the three and six months ended June 30, 2023, and the MD&A and audited consolidated financial statements of the Company for the year ended December 31, 2022. 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.sedar.com, including the Company's most recent Revised Annual Information Form dated May 11, 2023 ("AIF"). The Company's common shares are listed on the Toronto Stock Exchange under the trading symbol "ATH".

FOCUSED | EXECUTING | DELIVERING

ATHABASCA'S STRATEGY

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

- Thermal Oil: Predictable, Low Decline Production
- Light Oil - Montney at Placid and Duvernay at Kaybob: De-risked High Margin Liquids Rich Development
- Financial Sustainability: Low Leverage, Flexible Capital, Prudent Risk Management

Athabasca is currently focused on maximizing corporate free cash flow and maintaining its production base with low sustaining capital requirements. The Company has long term growth optionality across a deep inventory of high-quality Thermal Oil projects and flexible Light Oil development opportunities. This balanced portfolio provides shareholders with differentiated exposure to liquids weighted production and significant long reserve life assets.

SECOND QUARTER 2023 & RECENT HIGHLIGHTS

Corporate

- Production of 33,971 boe/d (93% Liquids(1)).
- Petroleum, natural gas & midstream sales of $282.6 million.
- Operating Income(1) of $95.1 million ($90.5 million Operating Income Net of Realized Hedging(1)).
- Operating Netback(1) of $32.23/boe ($30.67/boe Operating Netback Net of Realized Hedging(1)).
- Adjusted Funds Flow(1) of $81.7 million (cash flow from operating activities $46.9 million).
- Free Cash Flow(1) of $40.2 million supporting return of capital commitments.
- Liquidity(1) of $220.3 million, including $132.5 million of cash as at June 30, 2023.
- Share buyback program commenced in April and the Company has repurchased a total of 19.9 million common shares for $60.9 million year to date, representing approximately 34% of its annual Normal Course Issuer Bid ("NCIB") limit.

Thermal Oil Division

- Production of 29,016 bbl/d (21,240 bbl/d at Leismer and 7,776 bbl/d at Hangingstone).
- Petroleum, natural gas & midstream sales of $265.3 million.
- Operating Income(1) of $81.6 million.
- Operating Netback(1) of $32.64/bbl ($33.79/bbl at Leismer and $29.20/bbl at Hangingstone).
- Capital expenditures of $29.9 million; activity at Leismer during the quarter included converting four of five well pairs to production at Pad 8M, rig releasing four infill wells on Pad 7 and spudding four well pairs at Pad 8S.
- Leismer production is currently ~24,000 bbl/d supported by the recent tie-in of Pad 8M; the Company is progressing facility work for the expansion project with production expected to reach 28,000 bbl/d by mid-2024.

Light Oil Division

- Production of 4,955 boe/d (55% Liquids(1)).
- Petroleum, natural gas & midstream sales of $24.0 million.
- Operating Income(1) of $13.5 million.
- Operating Netback(1) of $29.92/boe.
- Capital expenditures of $10.8 million; activity was focused on operational readiness in advance of the upcoming drilling season.

(1) 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 June 30, 2023	2022	Six months ended June 30, 2023	2022
CONSOLIDATED				
Petroleum and natural gas production (boe/d)[1]	33,971	33,247	34,325	33,958
Petroleum, natural gas and midstream sales	$ 282,614	$ 435,678	$ 573,355	$ 825,102
Operating Income (Loss)[1]	$ 95,118	$ 169,255	$ 151,653	$ 319,895
Operating Income (Loss) Net of Realized Hedging[1][2]	$ 90,522	$ 103,549	$ 125,002	$ 206,543
Operating Netback ($/boe)[1]	$ 32.23	$ 57.51	$ 24.05	$ 52.26
Operating Netback Net of Realized Hedging ($/boe)[1][2]	$ 30.67	$ 35.18	$ 19.82	$ 33.74
Capital expenditures	$ 41,432	$ 51,191	$ 67,794	$ 82,120
THERMAL OIL DIVISION				
Bitumen production (bbl/d)[1]	29,016	26,768	29,097	27,335
Petroleum, natural gas and midstream sales	$ 265,304	$ 399,793	$ 534,406	$ 760,074
Operating Income (Loss)[1]	$ 81,621	$ 131,067	$ 123,118	$ 251,904
Operating Netback ($/bbl)[1]	$ 32.64	$ 55.68	$ 22.97	$ 51.17
Capital expenditures	$ 29,912	$ 43,093	$ 52,748	$ 64,275
LIGHT OIL DIVISION				
Petroleum and natural gas production (boe/d)[1]	4,955	6,479	5,228	6,623
Percentage Liquids (%)[1]	55%	58%	56%	57%
Petroleum, natural gas and midstream sales	$ 24,006	$ 53,825	$ 53,895	$ 98,933
Operating Income (Loss)[1]	$ 13,497	$ 38,188	$ 28,535	$ 67,991
Operating Netback ($/boe)[1]	$ 29.92	$ 64.77	$ 30.16	$ 56.72
Capital expenditures	$ 10,753	$ 1,221	$ 12,629	$ 9,208
CASH FLOW AND FUNDS FLOW				
Cash flow from operating activities	$ 46,914	$ 68,535	$ 67,451	$ 128,397
per share - basic	$ 0.08	$ 0.12	$ 0.11	$ 0.23
Adjusted Funds Flow[1]	$ 81,664	$ 84,799	$ 72,268	$ 159,560
per share - basic	$ 0.14	$ 0.15	$ 0.12	$ 0.29
Free Cash Flow[1]	$ 40,232	$ 33,608	$ 4,474	$ 77,440
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)				
Net income (loss) and comprehensive income (loss)	$ 57,121	$ 47,121	$ 486	$ (72,480)
per share - basic	$ 0.10	$ 0.08	$ 0.00	$ (0.13)
per share - diluted[3]	$ 0.07	$ 0.08	$ 0.00	$ (0.13)
COMMON SHARES OUTSTANDING				
Weighted average shares outstanding - basic	592,223,832	568,728,441	589,442,937	550,013,742
Weighted average shares outstanding - diluted	616,789,101	585,934,027	600,470,217	550,013,742

As at ($ Thousands)	June 30, 2023	December 31, 2022
LIQUIDITY AND BALANCE SHEET		
Cash and cash equivalents	$ 132,491	$ 197,525
Available credit facilities[4]	$ 87,838	$ 87,838
Face value of term debt[5]	$ 214,267	$ 237,231

(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) Includes realized commodity risk management loss of $4.6 million and $26.7 million for the three and six months ended June 30, 2023 (three and six months ended June 30, 2022 – loss of $65.7 million and $113.4 million).

(3) In the calculation of dilutive earnings per share for the three months ended June 30, 2023, earnings were reduced by $16.4 million to account for the impact to net income had the outstanding warrants and PSUs been converted to equity.

(4) Includes available credit under Athabasca's Credit Facility and Unsecured Letter of Credit Facility.

(5) The face value of the term debt at June 30, 2023 was US$162 million (December 31, 2022 – US$175 million) translated into Canadian dollars at the June 30, 2023 exchange rate of US$1.00 = C$1.3240 (December 31, 2022 – C$1.3544).

BUSINESS ENVIRONMENT

Benchmark prices

(Average)	Three months ended June 30, 2023	2022	Change	Six months ended June 30, 2023	2022	Change
Crude oil:						
West Texas Intermediate (WTI) (US$/bbl)[1]	$ 73.78	$ 108.41	(32) %	$ 74.95	$ 101.35	(26) %
West Texas Intermediate (WTI) (C$/bbl)[1]	$ 99.09	$ 138.39	(28) %	$ 100.98	$ 128.85	(22) %
Western Canadian Select (WCS) (C$/bbl)[2]	$ 78.80	$ 122.04	(35) %	$ 74.11	$ 111.50	(34) %
Edmonton Par (C$/bbl)[3]	$ 95.33	$ 137.83	(31) %	$ 97.34	$ 126.73	(23) %
Edmonton Condensate (C5+) (C$/bbl)[4]	$ 96.10	$ 137.70	(30) %	$ 100.77	$ 129.27	(22) %
WCS Differential:						
to WTI (US$/bbl)	$ (15.08)	$ (12.80)	18 %	$ (19.93)	$ (13.67)	46 %
to WTI (C$/bbl)	$ (20.29)	$ (16.35)	24 %	$ (26.87)	$ (17.35)	55 %
Edmonton Par Differential:						
to WTI (US$/bbl)	$ (2.98)	$ (0.50)	496 %	$ (2.92)	$ (1.73)	69 %
to WTI (C$/bbl)	$ (3.76)	$ (0.56)	571 %	$ (3.64)	$ (2.12)	72 %
Natural gas:						
AECO (C$/GJ)[5][6]	$ 2.32	$ 6.86	(66) %	$ 2.69	$ 5.68	(53) %
Foreign exchange:						
USD : CAD	1.3430	1.2765	5 %	1.3473	1.2713	6 %

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 the Company's Light Oil Division.
(4) Natural gas liquids condensate sales in the Company's Light Oil Division and for diluent purchases in the Thermal Oil Division.
(5) Natural gas consumed by Athabasca in order to generate steam in the Thermal Oil Division.
(6) Natural gas (i.e. shale gas and conventional natural gas) sales in the Company's Light Oil Division.

Global oil benchmarks have weakened year over year as global recession concerns weighed on commodities. However, the war in Ukraine has amplified the emphasis on energy security and sanctions continue to alter energy flows across the globe. Athabasca maintains a constructive outlook on oil prices supported by years of industry underinvestment, OPEC+ cuts and demand trends moving higher.

Canadian WCS heavy differentials narrowed significantly in the second quarter with differentials improving to US$15.08/bbl, compared to US$24.77/bbl in the first quarter of 2023. The supply-demand outlook for heavy barrels is expected to be supported by the continued OPEC+ production cuts, the start-up of the Trans Mountain Expansion pipeline (590,000 bbl/d) and the start-up of new global heavy oil refining capacity, specifically Pemex’s Dos Bocas 340,000 bbl/d refinery. These factors are expected to improve the strength of WCS prices into the second half of 2023 and 2024.

OUTLOOK

2023 Operational & Financial Guidance ($ millions, unless otherwise noted)	Guidance May 10, 2023	Updated Guidance July 26, 2023
Production (boe/d)(1)	34,500-36,000	34,500-36,000
% Liquids(1)	93%	93%
Adjusted Funds Flow(1)(2)(3)	$325-400	$310-365
Free Cash Flow(1)(2)(3)	$180-255	$165-220
Capital Expenditures	$145	$145
Thermal Oil	$120	$120
Light Oil	$25	$25

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP measures and production disclosure.
(2) Pricing assumptions for May 10, 2023 guidance: First quarter actual results and flat pricing of US$80-90 WTI, US$15 WCS heavy differential, C$3 AECO, and $0.74 C$/US$ FX for the remainder of 2023.
(3) Pricing assumptions for July 26, 2023 guidance: First half 2023 actual results and flat pricing of US$80-90 WTI, US$15 WCS heavy differential, C$3 AECO, and $0.75 C$/US$ FX for the remainder of 2023.

Athabasca's 2023 annual guidance remains unchanged at 34,500–36,000 boe/d (93% Liquids). Production is expected to grow annually by 5–7% through its current capital initiatives. The portfolio of long life assets underpin a low corporate decline of approximately 5% annually. The Company remains committed to executing a approximately $145 million capital program this year ($120 million Thermal and $25 million Light Oil) with activity focused on advancing the expansion project at Leismer and operational readiness in Light Oil.

Athabasca is committed to allocating a minimum of 75% of Excess Cash Flow (Adjusted Funds Flow less Sustaining Capital) in 2023 to shareholders through share buybacks. Additional Excess Cash Flow allocation will be commodity price dependent and could include additional share repurchases dependent on valuation, further debt reduction or high return growth projects.

Athabasca has excellent exposure to upside in commodity prices with 25% of forecasted 2023 production volumes hedged through collars, providing upside to approximately US$98.50 WTI.

CONSOLIDATED RESULTS

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

Consolidated Operating Results

	Three months ended June 30, 2023	2022	Six months ended June 30, 2023	2022
PRODUCTION				
Bitumen (bbl/d)	29,016	26,768	29,097	27,335
Oil and condensate (bbl/d)(1)	2,132	3,021	2,260	3,046
Natural gas (Mcf/d)(1)	13,345	16,325	13,848	16,974
Other natural gas liquids (bbl/d)(1)	599	737	660	748
Total (boe/d)(1)	33,971	33,247	34,325	33,958

(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 June 30, 2023	2022	Six months ended June 30, 2023	2022
Petroleum, natural gas and midstream sales(1)	$ 289,310	$ 453,618	$ 588,301	$ 859,007
Royalties	(12,281)	(61,521)	(24,450)	(99,886)
Cost of diluent(1)	(114,430)	(141,685)	(263,363)	(281,596)
Operating expenses	(46,700)	(59,185)	(101,398)	(111,660)
Transportation and marketing(2)	(20,781)	(21,972)	(47,437)	(45,970)
Operating Income (Loss)(3)	95,118	169,255	151,653	319,895
Realized gain (loss) on commodity risk mgmt. contracts	(4,596)	(65,706)	(26,651)	(113,352)
OPERATING INCOME (LOSS) NET OF REALIZED HEDGING(3)	$ 90,522	$ 103,549	$ 125,002	$ 206,543
REALIZED PRICES(3)				
Heavy oil (Blended bitumen) ($/bbl)(3)	$ 75.17	$ 119.83	$ 70.08	$ 107.60
Oil and condensate ($/bbl)(3)	93.33	133.72	96.56	124.84
Natural gas ($/Mcf)(3)	2.76	7.93	3.25	6.52
Other natural gas liquids ($/bbl)(3)	46.83	78.87	52.24	74.47
Realized price (net of cost of diluent) ($/boe)(3)	59.25	105.99	51.53	94.33
Royalties ($/boe)(3)	(4.16)	(20.90)	(3.88)	(16.32)
Operating expenses ($/boe)(3)	(15.82)	(20.11)	(16.08)	(18.24)
Transportation and marketing ($/boe)(2)(3)	(7.04)	(7.47)	(7.52)	(7.51)
Operating Netback ($/boe)(3)	32.23	57.51	24.05	52.26
Realized gain (loss) on commodity risk mgmt. contracts ($/boe)(3)	(1.56)	(22.33)	(4.23)	(18.52)
OPERATING NETBACK NET OF REALIZED HEDGING ($/boe)(3)	$ 30.67	$ 35.18	$ 19.82	$ 33.74

(1) Non-GAAP measure includes intercompany NGLs (i.e. condensate) sold by the Light Oil segment to the Thermal Oil segment for use as diluent that is eliminated on consolidation.
(2) Transportation and marketing excludes non-cash costs of $0.6 million and $1.1 million for the three and six months ended June 30, 2023 (three and six months ended June 30, 2022 - $0.6 million and $1.1 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.

Consolidated Segments Income (Loss)

($ Thousands)	Three months ended June 30, 2023	2022	Six months ended June 30, 2023	2022
Operating Income (Loss) Net of Realized Hedging[1]	$ 90,522	$ 103,549	$ 125,002	$ 206,543
Non-cash transportation and marketing	(558)	(558)	(1,115)	(1,115)
Unrealized gain (loss) on commodity risk mgmt. contracts	4,183	31,669	(782)	(52,199)
Depletion and depreciation	(28,099)	(28,522)	(56,593)	(56,776)
Gain (loss) on sale of assets	—	(14)	—	389
Exploration expenses	(81)	(282)	(393)	(484)
CONSOLIDATED SEGMENTS INCOME (LOSS)	$ 65,967	$ 105,842	$ 66,119	$ 96,358

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

Consolidated Capital Expenditures

($ Thousands)	Three months ended June 30, 2023	2022	Six months ended June 30, 2023	2022
Thermal Oil Division	$ 29,912	$ 43,093	$ 52,748	$ 64,275
Light Oil Division	10,753	1,221	12,629	9,208
Corporate assets	767	6,877	2,417	8,637
CAPITAL EXPENDITURES[1][2][3]	$ 41,432	$ 51,191	$ 67,794	$ 82,120

(1) For the three and six months ended June 30, 2023, expenditures include capitalized cash based stock-based compensation costs of $nil and $1.0 million (three and six months ended June 30, 2022 - $0.8 million and $2.5 million).

(2) For the three and six months ended June 30, 2023, expenditures include capitalized staff costs of $1.9 million and $3.8 million (three and six months ended June 30, 2022 - $2.2 million and $3.7 million).

(3) Excludes non-cash capitalized costs related to stock-based compensation, decommissioning obligation assets and leased asset modifications.

THERMAL OIL DIVISION

Athabasca's Thermal Oil Division consists 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 Division underpins 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 40 years and a reserve life index of approximately 85 years (proved plus probable). The Leismer Project has Proved plus Probable Reserves of approximately 698 MMbbl[1] and Best Estimate Development Pending Contingent Resources of 355 MMbbl (risked)[1] (395 MMbbl unrisked)[1]. The Corner lease has Proved plus Probable Reserves of approximately 353 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). Hangingstone has Proved plus Probable Reserves of approximately 170 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, 2022. 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 June 30, 2023	2022	Six months ended June 30, 2023	2022
VOLUMES				
Bitumen production (bbl/d)	21,240	17,436	20,970	18,197
Bitumen sales (bbl/d)	20,581	17,294	21,369	18,211
Heavy oil (blended bitumen) sales (bbl/d)	29,013	24,403	30,377	25,992

($ Thousands, unless otherwise noted)	Three months ended June 30, 2023	2022	Six months ended June 30, 2023	2022
Heavy oil (blended bitumen) sales	$ 196,366	$ 264,741	$ 381,926	$ 504,990
Cost of diluent	(86,182)	(93,447)	(191,556)	(185,375)
Total bitumen sales	110,184	171,294	190,370	319,615
Royalties	(8,218)	(36,706)	(13,039)	(59,433)
Operating expenses - non-energy	(15,647)	(14,440)	(32,507)	(28,512)
Operating expenses - energy	(11,898)	(18,458)	(25,975)	(33,312)
Transportation and marketing	(11,141)	(12,323)	(25,233)	(24,968)
LEISMER OPERATING INCOME (LOSS)[1]	$ 63,280	$ 89,367	$ 93,616	$ 173,390
REALIZED PRICE[1]				
Heavy oil (blended bitumen) sales ($/bbl)[1]	$ 74.38	$ 119.22	$ 69.46	$ 107.34
Bitumen sales ($/bbl)[1]	$ 58.83	$ 108.84	$ 49.22	$ 96.96
Royalties ($/bbl)[1]	(4.39)	(23.32)	(3.37)	(18.03)
Operating expenses - non-energy ($/bbl)[1]	(8.35)	(9.18)	(8.40)	(8.65)
Operating expenses - energy ($/bbl)[1]	(6.35)	(11.73)	(6.72)	(10.11)
Transportation and marketing ($/bbl)[1]	(5.95)	(7.83)	(6.52)	(7.57)
LEISMER OPERATING NETBACK ($/bbl)[1]	$ 33.79	$ 56.78	$ 24.21	$ 52.60

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

Leismer's bitumen production for the three and six months ended June 30, 2023 was 21,240 bbl/d and 20,970 bbl/d, an increase of 22% and 15%, respectively, compared to the corresponding periods in 2022. Production increases are primarily attributed to the ramp-up of Pad 8 (five well pairs) through 2022 and the additional new production from four of the five well pairs on Pad 8M late in the second quarter of 2023.

Leismer's Operating Netback was $33.79/bbl and $24.21/bbl for the three and six months ended June 30, 2023, respectively, representing a decrease of $22.99/bbl and $28.39/bbl compared with the same periods in 2022. The decrease is primarily due to lower WCS benchmark oil prices, partially offset by a decrease in Government and contingent bitumen royalties due to lower oil prices.

Total operating expenses were $14.70/bbl in the second quarter of 2023 and $15.12/bbl in the first six months of 2023, compared to $20.91/bbl and $18.76/bbl in the comparable periods of 2022. The decrease on a per barrel is largely the result of lower energy costs in the first half of 2023.

Hangingstone Operating Results

	Three months ended June 30, 2023	2022	Six months ended June 30, 2023	2022
VOLUMES				
Bitumen production (bbl/d)	7,776	9,332	8,127	9,138
Bitumen sales (bbl/d)	6,901	8,569	8,243	8,986
Heavy oil (blended bitumen) sales (bbl/d)	9,771	12,261	11,751	13,036

($ Thousands, unless otherwise noted)	Three months ended June 30, 2023	2022	Six months ended June 30, 2023	2022
Heavy oil (blended bitumen) and midstream sales	$ 68,938	$ 135,052	$ 152,480	$ 255,084
Cost of diluent	$ (28,248)	$ (48,238)	$ (71,807)	$ (96,221)
Total bitumen and midstream sales	40,690	86,814	80,673	158,863
Royalties	(2,726)	(19,205)	(4,518)	(28,974)
Operating expenses - non-energy	(5,241)	(6,005)	(11,321)	(12,248)
Operating expenses - energy	(6,819)	(12,539)	(17,571)	(22,866)
Transportation and marketing(1)	(7,563)	(7,365)	(17,761)	(16,261)
HANGINGSTONE OPERATING INCOME (LOSS)(2)	$ 18,341	$ 41,700	$ 29,502	$ 78,514
REALIZED PRICE(2)				
Heavy oil (blended bitumen) and midstream sales ($/bbl)(2)	$ 77.53	$ 121.04	$ 71.69	$ 108.11
Bitumen and midstream sales ($/bbl)(2)	$ 64.79	$ 111.33	$ 54.07	$ 97.67
Royalties ($/bbl)(2)	(4.34)	(24.63)	(3.03)	(17.81)
Operating expenses - non-energy ($/bbl)(2)	(8.35)	(7.70)	(7.59)	(7.53)
Operating expenses - energy ($/bbl)(2)	(10.86)	(16.08)	(11.78)	(14.06)
Transportation and marketing ($/bbl)(1)(2)	(12.04)	(9.44)	(11.90)	(10.00)
HANGINGSTONE OPERATING NETBACK ($/bbl)(2)	$ 29.20	$ 53.48	$ 19.77	$ 48.27

(1) Transportation and marketing excludes non-cash costs of $0.6 million and $1.1 million for the three and six months ended June 30, 2023 (three and six months ended June 30, 2022 - $0.6 million and $1.1 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 three and six months ended June 30, 2023 decreased compared to the same periods in 2022 as a result of natural declines and planned maintenance during May.

The Hangingstone Operating Netback was $29.20/bbl and $19.77/bbl for the three and six months ended June 30, 2023, representing a decrease of $24.28/bbl and $28.50/bbl, respectively, compared with the same periods in 2022. The decrease is primarily due to lower WCS benchmark oil prices, partially offset by a decrease in Government and contingent bitumen royalties due to the lower oil prices.

Total operating expenses were $19.21/bbl in the second quarter of 2023 and $19.37/bbl in the first six months of 2023, compared to $23.78/bbl and $21.59/bbl in the comparable periods of 2022. The decrease on a per barrel is the result of lower energy costs and a lower steam oil ratio in the first half of 2023, partially offset by lower production.

Consolidated Thermal Oil Operating Results

	Three months ended June 30, 2023	2022	Six months ended June 30, 2023	2022
VOLUMES				
Bitumen production (bbl/d)	29,016	26,768	29,097	27,335
Bitumen sales (bbl/d)	27,482	25,863	29,612	27,197
Heavy oil (blended bitumen) sales (bbl/d)	38,784	36,664	42,128	39,028

($ Thousands, unless otherwise noted)	Three months ended June 30, 2023	2022	Six months ended June 30, 2023	2022
Heavy oil (blended bitumen) and midstream sales	$ 265,304	$ 399,793	$ 534,406	$ 760,074
Cost of diluent	(114,430)	(141,685)	(263,363)	(281,596)
Total bitumen and midstream sales	150,874	258,108	271,043	478,478
Royalties	(10,944)	(55,911)	(17,557)	(88,407)
Operating expenses - non-energy	(20,888)	(20,445)	(43,828)	(40,760)
Operating expenses - energy	(18,717)	(30,997)	(43,546)	(56,178)
Transportation and marketing(1)	(18,704)	(19,688)	(42,994)	(41,229)
THERMAL OIL OPERATING INCOME (LOSS)(2)	$ 81,621	$ 131,067	$ 123,118	$ 251,904
REALIZED PRICE(2)				
Heavy oil (blended bitumen) and midstream sales ($/bbl)(2)	$ 75.17	$ 119.83	$ 70.08	$ 107.60
Bitumen and midstream sales ($/bbl)(2)	$ 60.33	$ 109.67	$ 50.57	$ 97.20
Royalties ($/bbl)(2)	(4.38)	(23.76)	(3.28)	(17.96)
Operating expenses - non-energy ($/bbl)(2)	(8.35)	(8.69)	(8.18)	(8.28)
Operating expenses - energy ($/bbl)(2)	(7.48)	(13.17)	(8.12)	(11.41)
Transportation and marketing ($/bbl)(1)(2)	(7.48)	(8.37)	(8.02)	(8.38)
THERMAL OIL OPERATING NETBACK ($/bbl)(2)	$ 32.64	$ 55.68	$ 22.97	$ 51.17

(1) Transportation and marketing excludes non-cash costs of $0.6 million and $1.1 million for the three and six months ended June 30, 2023 (three and six months ended June 30, 2022 - $0.6 million and $1.1 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 (Loss) 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.

Thermal Oil Segment Income (Loss)

($ Thousands)	Three months ended June 30, 2023	2022	Six months ended June 30, 2023	2022
Thermal Oil Operating Income (Loss)(1)	$ 81,621	$ 131,067	$ 123,118	$ 251,904
Non-cash transportation and marketing	(558)	(558)	(1,115)	(1,115)
Depletion and depreciation	(18,929)	(18,102)	(37,387)	(35,601)
Gain (loss) on sale of assets	—	(14)	—	389
Exploration expenses	(81)	(282)	(393)	(484)
THERMAL OIL SEGMENT INCOME (LOSS)	$ 62,053	$ 112,111	$ 84,223	$ 215,093

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

Depletion and depreciation increased $0.8 million and $1.8 million during the three and six months ended June 30, 2023, respectively, compared to the same periods in the prior year primarily due to higher production volumes at Leismer.

Thermal Oil Capital Expenditures

($ Thousands)	Three months ended June 30, 2023	2022	Six months ended June 30, 2023	2022
Leismer Project	$ 27,951	$ 40,955	$ 47,364	$ 60,036
Hangingstone Project	1,822	2,098	5,048	4,103
Other Thermal Oil exploration	139	40	336	136
THERMAL OIL CAPITAL EXPENDITURES(1)	$ 29,912	$ 43,093	$ 52,748	$ 64,275

(1) For the three and six months ended June 30, 2023, capital expenditures include $1.5 million and $3.0 million of capitalized staff costs (three and six months ended June 30, 2022 - $1.8 million and $2.9 million).

Thermal Oil capital expenditures for the six months ended June 30, 2023 of $52.7 million were primarily focused at Leismer along with routine pump replacements across both assets. At Leismer, the Company converted four of the five well pairs to production at Pad 8M, drilling and facilities work commenced at Pad 7 infills (four wells) and Pad 8S (four well pairs) and work continued on advancing the expansion project that will support growth to 28,000 bbl/d by mid-2024. At Hangingstone, Athabasca commenced the Pad AA extension for two future sustaining well pairs.

In comparison, capital expenditures for the first half of 2022 of $64.3 million were primarily related to sustaining operations and a planned facility turnaround at Leismer, along with routine pump replacements across both assets.

LIGHT OIL DIVISION

Athabasca produces light oil and liquids-rich natural gas from unconventional reservoirs. Development has been focused on the Montney in the Greater Placid area and the Duvernay in the Greater Kaybob area near the town of Fox Creek, Alberta. As at December 31, 2022, the Light Oil Division had approximately 70 MMboe of Proved plus Probable Reserves(1). Athabasca's Light Oil Division assets are supported by operated regional infrastructure consisting of four batteries and a network of gas pipelines which connect the facilities to two regional third party gas processing plants.

In Greater Placid, Athabasca has a 70% operated working interest in approximately 80,000 gross Montney acres. An inventory of approximately 150(2) gross development drilling locations positions the Company for multi-year development.

In Greater Kaybob, Athabasca has a 30% non-operated interest in approximately 195,000 gross acres of commercially prospective Duvernay lands with exposure to both Liquids-rich gas and volatile oil opportunities and an inventory of approximately 700(2) gross drilling locations.

(1) Based on the report of Athabasca's independent reserve evaluator effective December 31, 2022. 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.
(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information regarding the Company's drilling locations.

Light Oil Operating Results

	Three months ended June 30, 2023	2022	Six months ended June 30, 2023	2022
PRODUCTION[1]				
Oil and condensate (bbl/d)	2,132	3,021	2,260	3,046
Natural gas (Mcf/d)	13,345	16,325	13,848	16,974
Other natural gas liquids (bbl/d)	599	737	660	748
Total (boe/d)	4,955	6,479	5,228	6,623
Consisting of:				
Greater Placid area (boe/d)	2,664	3,275	2,752	3,419
% Liquids	40%	42%	42%	43%
Greater Kaybob area (boe/d)	2,291	3,204	2,476	3,204
% Liquids	72%	74%	72%	73%

(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 June 30, 2023	2022	Six months ended June 30, 2023	2022
Petroleum and natural gas sales	$ 24,006	$ 53,825	$ 53,895	$ 98,933
Royalties	(1,337)	(5,610)	(6,893)	(11,479)
Operating expenses	(7,095)	(7,743)	(14,024)	(14,722)
Transportation and marketing	(2,077)	(2,284)	(4,443)	(4,741)
LIGHT OIL OPERATING INCOME (LOSS)[1]	$ 13,497	$ 38,188	$ 28,535	$ 67,991
REALIZED PRICES[1]				
Oil and condensate ($/bbl)[1]	$ 93.33	$ 133.72	$ 96.56	$ 124.84
Natural gas ($/Mcf)[1]	2.76	7.93	3.25	6.52
Other natural gas liquids ($/bbl)[1]	46.83	78.87	52.24	74.47
Realized price ($/boe)[1]	53.24	91.29	56.96	82.53
Royalties ($/boe)[1]	(2.97)	(9.52)	(7.28)	(9.58)
Operating expenses ($/boe)[1]	(15.74)	(13.13)	(14.82)	(12.28)
Transportation and marketing ($/boe)[1]	(4.61)	(3.87)	(4.70)	(3.95)
LIGHT OIL OPERATING NETBACK ($/boe)[1]	$ 29.92	$ 64.77	$ 30.16	$ 56.72

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

Average Light Oil production for the three and six months ended June 30, 2023 decreased as a result of natural declines.

The Operating Netback was $29.92/boe and $30.16/boe for the three and six months ended June 30, 2023, respectively, the decrease is primarily due to lower commodity prices, higher operating expenses on a per boe basis correlated to lower production volumes, partially offset by a decrease in royalties primarily due to lower commodity prices and an annual gas cost allowance adjustment from the Crown.

Light Oil Segment Income (Loss)

($ Thousands)	Three months ended June 30, 2023	2022	Six months ended June 30, 2023	2022
Light Oil Operating Income (Loss)(1)	$ 13,497	$ 38,188	$ 28,535	$ 67,991
Depletion and depreciation	(9,170)	(10,420)	(19,206)	(21,175)
LIGHT OIL SEGMENT INCOME (LOSS)	$ 4,327	$ 27,768	$ 9,329	$ 46,816

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

Depletion and depreciation decreased $1.3 million and $2.0 million during the three and six months ended June 30, 2023, respectively, compared to the same periods in the prior year primarily due to lower production volumes.

Light Oil Capital Expenditures

($ Thousands)	Three months ended June 30, 2023	2022	Six months ended June 30, 2023	2022
Greater Placid	$ 10,906	$ 453	$ 12,659	$ 1,401
Greater Kaybob	(153)	768	(30)	7,807
LIGHT OIL CAPITAL EXPENDITURES(1)	$ 10,753	$ 1,221	$ 12,629	$ 9,208

(1) For the three and six months ended June 30, 2023, capital expenditures include $0.4 million and $0.8 million of capitalized staff costs (three and six months ended June 30, 2022 - $0.4 million and $0.8 million).

Light Oil capital expenditures for the six months ended June 30, 2023 of $12.6 million was focused on operational readiness in advance of the upcoming drilling season.

In comparison, capital expenditures for the first half of 2022 of $9.2 million were primarily incurred at Greater Kaybob for the completion and infrastructure work for three gross wells and two facility turnarounds at Kaybob West and Kaybob East.

CORPORATE REVIEW

Liquidity and Capital Resources

Funding

For 2023, 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 a portion of its forecasted Free Cash Flow in 2023 to share buybacks with flexibility for further debt reduction and high return growth projects. An active commodity risk management program and maintaining sufficient liquidity will allow the Company to manage periods of volatility.

As at June 30, 2023, Athabasca had Liquidity of $220.3 million which included $132.5 million of cash and cash equivalents and $87.8 million of available capacity on its credit facilities.

Indebtedness

Athabasca had the following debt instruments and credit facilities in place as at June 30, 2023:

Term Debt

As at June 30, 2023, the principal balance on Athabasca’s senior secured second lien notes (“2026 Notes” or “Notes”) was $214.3 million (US$161.8 million). During the first quarter of 2023 the Company redeemed $18.3 million (US$13.3 million) of the Notes through open market purchases and achieved a 54% reduction in the principal balance from the original US$350 million Notes issuance in the fourth quarter of 2021. Within the first quarter of 2023 the Excess Cash Flow ("ECF") feature was terminated within the indenture as the principal balance was below US$175 million.

The Notes are due November 1, 2026 and bear interest at 9.75% per annum. Athabasca may redeem all or part of the 2026 Notes at any time prior to November 1, 2024 at 100% of the principal amount plus an applicable premium, as set out in the 2026 Note indenture. On or after November 1, 2024, Athabasca may redeem all or part of the 2026 Notes at 104.875% from November 1, 2024 to November 1, 2025 and at 100% from November 1, 2025 to November 1, 2026.

Credit Facility

In the first quarter of 2023, Athabasca renewed its $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, 2024, 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, 2025. The Credit Facility is subject to a semi-annual borrowing base review, occurring in May and November 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 June 30, 2023, the Company had no amounts drawn and $27.1 million of letters of credit outstanding under the Credit Facility. As at December 31, 2022, the Company had no amounts drawn and $34.4 million of letters of credit outstanding under the Credit Facility.

Unsecured Letter of Credit Facility

Athabasca maintains a $60.0 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 (December 31, 2022 - $60.0 million). The facility is available on a demand basis and letters of credit issued under this facility incur an issuance and performance guarantee fee of 3.0%. As at June 30, 2023, the Company had $55.1 million of letters of credit outstanding under the Unsecured Letter of Credit Facility (December 31, 2022 - $47.8 million).

Financing and Interest

	Three months ended June 30,		Six months ended June 30,	
($ Thousands)	**2023**	**2022**	**2023**	**2022**
Financing and interest expense on indebtedness	$ 6,241	$ 17,063	$ 13,751	$ 30,013
Accretion of 2026 Notes	1,810	(330)	(1,592)	18,307
Accretion of warrants	371	2,047	449	2,245
Accretion of provisions	1,946	2,584	3,865	5,269
Interest expense on lease liability	148	237	325	494
TOTAL FINANCING AND INTEREST	$ 10,516	$ 21,601	$ 16,798	$ 56,328

During the three and six months ended June 30, 2023 and 2022, total financing and interest expenses were primarily attributable to the financing, interest and accretion expenses related to the Company's Notes. Accretion of the 2026 Notes decreased in the first half of 2023 as a result of the early redemption requirement of the Notes no longer being applicable with the termination of the ECF in the first quarter of 2023.

Foreign Exchange Gain (Loss), Net

	Three months ended June 30,		Six months ended June 30,	
($ Thousands)	**2023**	**2022**	**2023**	**2022**
Unrealized foreign exchange gain (loss)	$ 1,766	$ (1,422)	$ 4,422	$ 1,733
Realized foreign exchange gain (loss)	(564)	(1,832)	(1,758)	(3,117)
FOREIGN EXCHANGE GAIN (LOSS), NET	$ 1,202	$ (3,254)	$ 2,664	$ (1,384)

Athabasca is exposed to foreign currency risk primarily on the principal and interest components of its US dollar denominated term debt partially offset by its US dollar cash balances. The unrealized foreign exchange gains (losses) recognized were primarily due to unrealized gains (losses) on the note principal as the value of the Canadian dollar fluctuates relative to the US dollar.

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 June 30, 2023, 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*
WTI collar	July - September 2023	10,000 bbl/d	$	66.20 - 141.04	$	50.00 - 106.53
WTI collar	October - December 2023	2,330 bbl/d	$	66.20 - 138.58	$	50.00 - 104.67
Purchase contracts				*C$/GJ/bbl*		*US$/GJ/bbl*
AECO fixed price swaps	July - December 2023	20,000 GJ/d	$	4.90	$	3.70
WTI/C5+ differential swap	October - December 2023	1,000 bbl/d	$	(4.04)	$	(3.05)

(1) The implied C$ or US$ Average Price per bbl or GJ, as applicable, was calculated using the June 30, 2023 exchange rate of US$1.00 = C$1.3240.

In 2021, Athabasca entered into a seven-year marketing agreement for 15,000 bbl/d with an industry counterparty that will diversify 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 June 30, 2023, the pricing derivative had an asset value of $0.3 million (December 31, 2022 - $0.8 million).

The following table summarizes the Company's net gain (loss) on commodity risk management contracts for the three and six months ended June 30, 2023 and 2022:

($ Thousands)		Three months ended June 30, 2023		2022		Six months ended June 30, 2023		2022
Unrealized gain (loss) on commodity risk mgmt. contracts	$	4,183	$	31,669	$	(782)	$	(52,199)
Realized gain (loss) on commodity risk mgmt. contracts		(4,596)		(65,706)		(26,651)		(113,352)
GAIN (LOSS) ON COMMODITY RISK MGMT. CONTRACTS, NET	$	(413)	$	(34,037)	$	(27,433)	$	(165,551)

At June 30, 2023, a US$5 increase/decrease in the price of WTI has a nil impact on the WTI collar contracts. The following table summarizes the sensitivity to price changes for Athabasca's other commodity risk management contracts:

As at June 30, 2023		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	$	4,739	$	(4,739)

Additional financial commodity risk management has taken place subsequent to June 30, 2023 as noted in the table below:

Instrument	Period	Volume		C$ Average Price[(1)]		US$ Average Price[(1)]
Sales contracts				*C$/bbl*		*US$/bbl*
WTI collar	July - September 2023	13,000 bbl/d	$	66.20 - 120.62	$	50.00 - 91.11
WTI collar	October - December 2023	8,855 bbl/d	$	66.20 - 130.27	$	50.00 - 98.39

(1) The implied C$ or US$ Average Price per bbl or GJ, as applicable, was calculated using the June 30, 2023 exchange rate of US$1.00 = C$1.3240.

Commitments and Contingencies

The following table summarizes Athabasca's estimated future unrecognized minimum commitments as at June 30, 2023 for the following five years and thereafter:

($ Thousands)	Remaining 2023	2024	2025	2026	2027	Thereafter	Total
Transportation and processing[(1)]	$ 58,282	$ 112,940	$ 109,053	$ 108,486	$ 104,975	$ 1,051,466	$ 1,545,202
Interest expense on term debt[(1)]	10,446	20,891	20,891	17,409	—	—	69,637
Purchase commitments and other[(1)]	9,447	3,679	—	—	—	—	13,126
TOTAL COMMITMENTS	$ 78,175	$ 137,510	$ 129,944	$ 125,895	$ 104,975	$ 1,051,466	$ 1,627,965

(1) Commitments which are denominated in US dollars were translated into Canadian dollars at the June 30, 2023 exchange rate of US$1.00 = C$1.3240.

The Company is, from time to time, involved in claims arising in the normal course of business. The Company is currently undergoing tax and partner related audits in the normal course of business. The final outcome of such audits cannot be predicted with certainty, however, management concluded that it has appropriately assessed any impact to the consolidated financial statements.

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 June 30, 2023. 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's exposure to interest rate fluctuations on interest earned on its floating rate cash and cash equivalents balance at June 30, 2023 of $132.5 million (December 31, 2022 - $197.5 million), from a 1.0% change in interest rates, would have an annualized impact of approximately $1.3 million (December 31, 2022 - $2.0 million). The 2026 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 June 30, 2023	2022	Six months ended June 30, 2023	2022
TOTAL GENERAL AND ADMINISTRATIVE	$ 4,670	$ 4,941	$ 10,417	$ 9,362
G&A per boe[(1)]	$ 1.51	$ 1.63	$ 1.68	$ 1.52

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

Stock Based Compensation

During the three and six months ended June 30, 2023, Athabasca's stock-based compensation expense was $0.2 million and $35.2 million, respectively, compared to $8.4 million and $21.8 million in the respective prior year periods. During the first quarter of 2023, the Company elected for the 2020 PSUs vesting April 1, 2023 to be settled in cash to reduce share dilution in advance of its proposed share buyback program which commenced in the second quarter of 2023. The PSUs plan was historically accounted for as an equity-settled stock-based compensation plan and has now been accounted for with the PUPs and DSUs as cash-settled stock-based compensation plans and are recognized as liabilities on the Consolidated Balance Sheet. The March 31, 2023 PSUs election resulted in the recognition of a $26.3 million liability on the Consolidated Balance Sheet and a $24.2 million cash based stock-based compensation expense on the Consolidated Statements of Income (Loss).

Gain (Loss) on Revaluation of Provisions and Other

($ Thousands)	Three months ended June 30, 2023	2022	Six months ended June 30, 2023	2022
Change in fair value of warrant liability	$ 16,476	$ (17,424)	$ (7,338)	$ (76,369)
Change in estimated decommissioning obligations related to fully impaired E&E assets	—	(3,073)	—	(3,073)
Other	—	299	—	367
GAIN (LOSS) ON REVALUATION OF PROVISIONS AND OTHER	$ 16,476	$ (20,198)	$ (7,338)	$ (79,075)

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 2022 and 2023 primarily relate to changes in the share price.

Income Taxes

In the first six months of 2023 a $2.3 million deferred income tax expense was recorded (first six months of 2022 - $nil) resulting in a June 30, 2023 deferred income tax asset of $411.0 million (December 31, 2022 - $413.3 million). The Company has approximately $3.1 billion in tax pools, including approximately $2.4 billion in non-capital losses and exploration tax pools available for immediate deduction against future income.

From time to time, Athabasca undergoes income tax audits in the normal course of business. In 2018, the Company received a notice of reassessment from the Canada Revenue Agency ("CRA") and Alberta Finance with regards to its 2012 taxation year resulting in a $12.6 million deposit posted with the CRA. In the second quarter of 2023, Athabasca successfully appealed the reassessment and the $12.6 million was fully refunded.

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 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 June 30, 2023, there were 585.7 million common shares outstanding, an aggregate of 11.6 million restricted share units and performance share units outstanding, 5.6 million stock options outstanding and 22.7 million (15.2 million assuming cashless exercise at June 30, 2023 share price) potential shares issuable under warrants agreements (99,999 warrants outstanding).

As at June 30, 2023, the Company repurchased for cancellation 15.6 million common shares under its NCIB program, for total consideration of $46.9 million. Subsequent to June 30, 2023, the Company repurchased for cancellation 4.3 million common shares under its NCIB program, for total consideration of $14.0 million.

As at July 26, 2023, there were 581.4 million common shares outstanding, an aggregate of 11.6 million restricted share units and performance share units outstanding, 5.6 million stock options outstanding and 22.7 million (16.6 million assuming cashless exercise at July 25, 2023 share price) potential shares issuable under warrants agreements (99,999 warrants outstanding).

SUMMARY OF QUARTERLY RESULTS

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

	2023		2022				2021	
($ Thousands, unless otherwise noted)	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	73.78	76.13	82.65	91.55	108.41	94.29	77.19	70.56
WTI (C$/bbl)	99.09	102.92	112.21	119.54	138.39	119.38	97.25	88.91
Western Canadian Select (C$/bbl)	78.80	69.42	77.36	93.48	122.04	100.96	78.67	71.77
Edmonton Par (C$/bbl)	95.33	99.34	110.13	116.79	137.83	115.62	93.14	83.70
Edmonton Condensate (C5+) (C$/bbl)	96.10	105.44	111.82	112.87	137.70	120.84	99.24	86.78
AECO (C$/GJ)	2.32	3.05	4.85	3.95	6.86	4.49	4.41	3.41
Foreign exchange (USD : CAD)	1.34	1.35	1.36	1.31	1.28	1.27	1.26	1.26
CONSOLIDATED								
Petroleum and natural gas production (boe/d)(1)	33,971	34,683	35,850	37,240	33,247	34,679	35,147	34,255
Realized price (net of cost of diluent) ($/boe)(1)	59.25	44.74	53.84	75.10	105.99	83.53	63.89	60.40
Petroleum, natural gas and midstream sales ($)(2)	289,310	298,991	292,105	406,794	453,618	405,389	305,313	291,300
Operating Income (Loss) ($)(1)	95,118	56,535	70,319	140,081	169,255	150,640	110,648	120,581
Operating Income (Loss) Net of Realized Hedging ($)(1)	90,522	34,480	62,131	110,021	103,549	102,994	65,735	92,742
Operating Netback ($/boe)(1)	32.23	16.85	23.17	39.17	57.51	47.40	35.43	36.02
Operating Netback Net of Realized Hedging ($/boe)(1)	30.67	10.27	20.47	30.76	35.18	32.41	21.05	27.70
Capital expenditures ($)	41,432	26,362	13,029	52,300	51,191	30,929	18,352	15,608
THERMAL OIL DIVISION								
Bitumen production (bbl/d)	29,016	29,179	30,210	31,023	26,768	27,909	28,084	26,729
Bitumen sales volumes (bbl/d)	27,482	31,765	27,346	32,650	25,863	28,545	26,889	28,852
Realized bitumen price ($/bbl)(1)	60.33	42.03	50.49	76.09	109.67	85.78	64.40	62.39
Heavy Oil (blended bitumen) and midstream sales ($)	265,304	269,102	255,749	366,804	399,793	360,281	265,076	254,769
Operating Income (Loss) ($)(1)	81,621	41,497	50,691	117,916	131,067	120,837	82,729	94,796
Operating Netback ($/bbl)(1)	32.64	14.52	20.15	39.25	55.68	47.04	33.43	35.71
Capital expenditures ($)	29,912	22,836	10,895	35,412	43,093	21,182	12,355	15,228
LIGHT OIL DIVISION								
Petroleum and natural gas production (boe/d)(1)	4,955	5,504	5,640	6,217	6,479	6,770	7,063	7,526
Realized price ($/boe)(1)	53.24	60.34	70.07	69.92	91.29	74.03	61.92	52.76
Petroleum and natural gas sales ($)(2)	24,006	29,889	36,356	39,990	53,825	45,108	40,237	36,531
Operating Income (Loss) ($)(1)	13,497	15,038	19,628	22,165	38,188	29,803	27,919	25,785
Operating Netback ($/boe)(1)	29.92	30.35	37.83	38.76	64.77	48.92	42.95	37.25
Capital expenditures ($)	10,753	1,876	1,594	860	1,221	7,987	5,291	128
OPERATING RESULTS								
Cash flow from operating activities ($)	46,914	20,537	69,368	117,853	68,535	59,862	81,189	75,743
Adjusted Funds Flow ($)(1)	81,664	(9,396)	46,074	102,370	84,799	74,761	42,643	72,233
Net income (loss) ($)	57,121	(56,635)	489,654	155,097	47,121	(119,601)	384,073	104,951
Net income (loss) per share - basic ($)	0.10	(0.10)	0.83	0.27	0.08	(0.23)	0.72	0.20
BALANCE SHEET ITEMS								
Cash and cash equivalents ($)	132,491	173,280	197,525	200,100	154,172	213,534	223,056	273,989
Restricted cash ($)	—	—	—	—	—	—	—	46,107
Total assets ($)	2,162,091	2,210,487	2,230,354	1,803,624	1,815,390	1,814,662	1,742,131	1,510,924
Term debt ($)(3)	181,577	184,509	206,133	240,078	250,756	355,328	384,298	568,428
Shareholders' equity ($)	1,682,906	1,655,044	1,710,497	1,218,174	1,057,355	909,852	1,025,959	640,542

(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) Includes intercompany NGLs (i.e. condensate) sold by the Light Oil segment to the Thermal Oil segment for use as diluent that is eliminated on consolidation.
(3) 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.

ACCOUNTING POLICIES AND ESTIMATES

During the six months ended June 30, 2023, 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 11 Stock-based Compensation of the Consolidated Financial Statements. A summary of the significant accounting policies, including the use of estimates and judgments, used by Athabasca can be found in Note 3 of the December 31, 2022 audited consolidated financial statements. All of the estimates and judgments are subject to measurement uncertainty and changes in these estimates could materially impact the consolidated financial statements of future periods and have a significant impact on net income (loss).

ADVISORIES AND OTHER GUIDANCE

Non-GAAP and Other Financial Measures, and Production Disclosure

The "Adjusted Funds Flow", "Adjusted Funds Flow per Share", "Free Cash Flow", "Light Oil Operating Income", "Light Oil Operating Netback", "Thermal Oil Operating Income", "Thermal Oil Operating Netback", "Consolidated Operating Income", "Consolidated Operating Netback", "Consolidated Operating Income Net of Realized Hedging", "Consolidated Operating Netback Net of Realized Hedging", "Realized Prices", "Cash Transportation & Marketing Expenses", "Excess Cash Flow" and "Sustaining Capital" 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 Thermal Oil segment results and the Greater Placid and Greater Kaybob operating results are supplementary financial measures that when aggregated, combine to the Light Oil segment results.

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

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

($ Thousands)	Three months ended June 30, 2023	2022	Six months ended June 30, 2023	2022
Cash flow from operating activities	$ 46,914	$ 68,535	$ 67,451	$ 128,397
Changes in non-cash working capital	34,630	16,353	16,600	30,706
Settlement of provisions	120	(89)	794	457
Long-term deposit	—	—	(12,577)	—
ADJUSTED FUNDS FLOW	81,664	84,799	72,268	159,560
Capital expenditures	(41,432)	(51,191)	(67,794)	(82,120)
FREE CASH FLOW	$ 40,232	$ 33,608	$ 4,474	$ 77,440

Operating Income (Loss) 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 table on page 12 reconciles Light Oil Operating Income to its segmented income in *Note 13 - Segmented Information* of the Consolidated Financial Statements for the three and six months ended June 30, 2023. The table on page 9 reconciles Thermal Oil Operating Income to its segmented income in *Note 13 - Segmented Information* of the Consolidated Financial Statements for the three and six months ended June 30, 2023.

The non-GAAP measure 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 Consolidated Operating Netback Net of Realized Hedging measure per boe is a non-GAAP financial ratio calculated by dividing Consolidated Operating Income Net of Realized Hedging by the total sales volumes. The Consolidated Operating Income Net of Realized Hedging and the Consolidated Operating Netback Net of Realized Hedging measures allow management and others to evaluate the production results from the Company's Light Oil and Thermal Oil assets combined together including the impact of realized commodity risk management gains or losses. The table on page 6 reconciles Consolidated Operating Income Net of Realized Hedging to Consolidated segment income in *Note 13 - Segmented Information* of the Consolidated Financial Statements for the three and six months ended June 30, 2023.

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 & Marketing Expenses

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

Excess Cash Flow and Sustaining Capital

The Excess Cash Flow and Sustaining Capital measures allow management and others to evaluate the Company's ability to return capital to Shareholders. Sustaining Capital is managements' assumption of the required capital to maintain the Company's production base. The Excess Cash Flow measure is calculated by Adjusted Funds Flow less Sustaining Capital.

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

Production		Three months ended June 30, 2023	2022	Six months ended June 30, 2023	2022
Greater Placid:					
Condensate NGLs	bbl/d	720	1,002	767	1,051
Other NGLs	bbl/d	350	384	376	410
Natural gas[1]	mcf/d	9,563	11,337	9,650	11,750
Total Greater Placid	boe/d	2,664	3,275	2,752	3,419
Greater Kaybob:					
Oil[2]	bbl/d	1,412	2,019	1,493	1,995
Other NGLs	bbl/d	249	353	284	338
Natural gas[1]	mcf/d	3,782	4,988	4,198	5,224
Total Greater Kaybob	boe/d	2,291	3,204	2,476	3,204
Light Oil:					
Oil[2]	bbl/d	1,412	2,019	1,493	1,995
Condensate NGLs	bbl/d	720	1,002	767	1,051
Oil and condensate NGLs	bbl/d	2,132	3,021	2,260	3,046
Other NGLs	bbl/d	599	737	660	748
Natural gas[1]	mcf/d	13,345	16,325	13,848	16,974
Total Light Oil division	boe/d	4,955	6,479	5,228	6,623
Total Thermal Oil division bitumen	bbl/d	29,016	26,768	29,097	27,335
Total Company production	boe/d	33,971	33,247	34,325	33,958

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

Liquids:		Three months ended June 30, 2023	2022	Six months ended June 30, 2023	2022
Greater Placid:					
Condensate NGLs	bbl/d	720	1,002	767	1,051
Other NGLs	bbl/d	350	384	376	410
Total Greater Placid Liquids	bbl/d	1,070	1,386	1,143	1,461
as % of Greater Placid production		40%	42%	42%	43%
Greater Kaybob:					
Oil	bbl/d	1,412	2,019	1,493	1,995
Other NGLs	bbl/d	249	353	284	338
Total Greater Kaybob Liquids	bbl/d	1,661	2,372	1,777	2,333
as % of Greater Kaybob production		73%	74%	72%	73%
Total Light Oil:					
Oil and condensate NGLs	bbl/d	2,132	3,021	2,260	3,046
Other NGLs	bbl/d	599	737	660	748
Total Light Oil division Liquids	bbl/d	2,731	3,758	2,920	3,794
as % of Light Oil production		55%	58%	56%	57%
Total Company:					
Total Light Oil division Liquids	bbl/d	2,731	3,758	2,920	3,794
Total Thermal Oil division bitumen	bbl/d	29,016	26,768	29,097	27,335
Total Company Liquids	bbl/d	31,747	30,526	32,017	31,129
as % of Company production		93%	92%	93%	92%

This MD&A also makes reference to Athabasca's forecasted total average daily production of 34,500 - 36,000 boe/d for 2023. Athabasca expects that approximately 86% of that production will be comprised of bitumen, 6% shale gas, 4% tight oil, 2% condensate natural gas liquids and 2% other natural gas liquids.

Disclosure Control and Procedures

Athabasca is required to comply with National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109"). NI 52-109 requires that Athabasca disclose in its interim MD&A any material weaknesses in Athabasca's internal control over financial reporting and/or any changes in Athabasca's internal control over financial reporting that occurred during the period that have materially affected, or are reasonably likely to materially affect, Athabasca's internal controls over financial reporting. Athabasca confirms that no material weaknesses or such changes were identified in Athabasca's internal controls over financial reporting during the second quarter of 2023.

Risk Factors

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 Division development projects, the exploration and development of Athabasca's Light Oil assets and the levels and timing of anticipated production;
- dependence upon Murphy as a working interest participant in its Light Oil assets and as operator of the 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; and
- inaccuracy of forward-looking information.

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.sedar.com.

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 corporate, Thermal Oil and Light Oil production levels; reserve life index; on stream timing of additional well pairs and timing of expansion projects at Leismer; the Company's anticipated sources of funding for 2023 and beyond; the Company's use of Excess Cash Flow, including in respect of share buybacks; 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, 2022 (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.sedar.com, including, but not limited to: weakness in the oil and gas industry; exploration, development and production risks; prices, markets and marketing; market conditions; 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; continued impact of the COVID-19 pandemic; 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 and 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; 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.sedar.com. 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, 2022. 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.sedar.com.

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 700 Duvernay drilling locations referenced in this MD&A include: 5 proved undeveloped locations and 77 probable undeveloped locations for a total of 82 booked locations with the balance being unbooked locations. The 150 Montney drilling locations referenced in this MD&A include: 48 proved undeveloped locations and 50 probable undeveloped locations for a total of 98 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, 2022 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, 2022, 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