Management's Discussion and Analysis

December 31, 2022

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 March 1, 2023 and should be read in conjunction with the audited consolidated financial statements of the Company for the years ended December 31, 2022 and 2021 ("Consolidated Financial Statements"). 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 Annual Information Form dated March 1, 2023 ("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 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.

HIGHLIGHTS FOR THE QUARTER AND YEAR ENDED DECEMBER 31, 2022

Corporate

- Fourth quarter production of 35,850 boe/d (93% Liquids(1)) and 2022 production of 35,262 boe/d (92% Liquids(1)).
- Petroleum, natural gas & midstream sales of $282.5 million in the fourth quarter and $1.5 billion for 2022.
- Operating Income(1) of $70.3 million ($62.1 million Operating Income Net of Realized Hedging(1)) in the fourth quarter and $530.3 million ($378.7 million Operating Income Net of Realized Hedging(1)) for 2022.
- Operating Netback(1) of $23.17/boe ($20.47/boe Operating Netback Net of Realized Hedging(1)) in the fourth quarter and $41.65/boe ($29.74/boe Operating Netback Net of Realized Hedging(1)) for 2022.
- Fourth quarter Adjusted Funds Flow(1) of $46.1 million (cash flow from operating activities $69.4 million) and $308.0 million (cash flow from operating activities $315.6 million) for 2022.
- Fourth quarter Free Cash Flow(1) of $33.0 million and $160.6 million for 2022.
- Liquidity(1) of $285.3 million, including $197.5 million of cash as at December 31, 2022.
- Redeemed a total of $227.3 million (US$174.8 million) of the 2026 Notes in 2022, which represents 99.9% of the Company's debt reduction target of US$175 million or 50% from the original US$350 million Notes issuance.

Thermal Oil Division

- Fourth quarter production of 30,210 bbl/d and 2022 production of 28,989 bbl/d.
- Petroleum, natural gas & midstream sales of $255.7 million in the fourth quarter and $1.4 billion for 2022.
- Operating Income(1) of $50.7 million for the fourth quarter and $420.5 million for 2022.
- Operating Netback(1) of $20.15/bbl in the fourth quarter and $40.26/bbl for 2022.
- Capital expenditures of $110.6 million for 2022. Activity was focused on Leismer and included a planned facility turnaround in May, converting five Pad 8 sustaining well pairs and two Pad 6 infill wells to production, and rig releasing the Pad 8 expansion (five additional well pairs) which are expected to be on production in 2023.

Light Oil Division

- Fourth quarter production of 5,640 boe/d (56% Liquids(1)) and 2022 production of 6,273 boe/d (57% Liquids(1)).
- Petroleum, natural gas & midstream sales of $36.4 million in the fourth quarter and $175.3 million for 2022.
- Operating Income(1) of $19.6 million for the fourth quarter and $109.8 million for 2022.
- Operating Netback(1) of $37.83/boe in the fourth quarter and $47.95/boe for 2022.
- Capital expenditures of $11.7 million for 2022 were primarily incurred at Greater Kaybob for completions operations on three gross wells and two facility turnarounds at Kaybob West and Kaybob East.

(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 December 31, 2022	2021	Year ended December 31, 2022	2021
CONSOLIDATED				
Petroleum and natural gas production (boe/d)[1]	35,850	35,147	35,262	34,618
Petroleum, natural gas and midstream sales	$ 282,524	$ 292,405	$ 1,504,685	$ 1,016,323
Operating Income (Loss)[1]	$ 70,319	$ 110,648	$ 530,295	$ 390,353
Operating Income (Loss) Net of Realized Hedging[1][2]	$ 62,131	$ 65,735	$ 378,695	$ 278,664
Operating Netback ($/boe)[1]	$ 23.17	$ 35.43	$ 41.65	$ 31.00
Operating Netback Net of Realized Hedging ($/boe)[1][2]	$ 20.47	$ 21.05	$ 29.74	$ 22.13
Capital expenditures	$ 13,029	$ 18,352	$ 147,449	$ 92,142
Free Cash Flow[1]	$ 33,045	$ 24,291	$ 160,555	$ 91,923
THERMAL OIL DIVISION				
Bitumen production (bbl/d)[1]	30,210	28,084	28,989	26,805
Petroleum, natural gas and midstream sales	$ 255,749	$ 265,076	$ 1,382,627	$ 914,058
Operating Income (Loss)[1]	$ 50,691	$ 82,729	$ 420,511	$ 287,261
Operating Netback ($/bbl)[1]	$ 20.15	$ 33.43	$ 40.26	$ 29.49
Capital expenditures	$ 10,895	$ 12,355	$ 110,582	$ 81,985
LIGHT OIL DIVISION				
Petroleum and natural gas production (boe/d)[1]	5,640	7,063	6,273	7,813
Percentage Liquids (%)[1]	56%	56%	57%	56%
Petroleum, natural gas and midstream sales	$ 36,356	$ 40,237	$ 175,279	$ 147,705
Operating Income (Loss)[1]	$ 19,628	$ 27,919	$ 109,784	$ 103,092
Operating Netback ($/boe)[1]	$ 37.83	$ 42.95	$ 47.95	$ 36.15
Capital expenditures	$ 1,594	$ 5,291	$ 11,662	$ 6,931
CASH FLOW AND FUNDS FLOW				
Cash flow from operating activities	$ 69,368	$ 81,189	$ 315,618	$ 194,253
per share - basic	$ 0.12	$ 0.15	$ 0.56	$ 0.37
Adjusted Funds Flow[1]	$ 46,074	$ 42,643	$ 308,004	$ 184,065
per share - basic	$ 0.08	$ 0.08	$ 0.54	$ 0.35
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)				
Net income (loss) and comprehensive income (loss)	$ 489,654	$ 384,073	$ 572,271	$ 457,608
per share - basic	$ 0.83	$ 0.72	$ 1.01	$ 0.86
per share - diluted	$ 0.81	$ 0.70	$ 0.98	$ 0.84
COMMON SHARES OUTSTANDING				
Weighted average shares outstanding - basic	586,468,394	530,744,156	568,035,589	530,692,724
Weighted average shares outstanding - diluted	604,911,603	551,124,848	586,913,328	546,717,181

As at ($ Thousands)	December 31, 2022	December 31, 2021
LIQUIDITY AND BALANCE SHEET		
Cash and cash equivalents	$ 197,525	$ 223,056
Available credit facilities[3]	$ 87,838	$ 77,844
Face value of term debt[4]	$ 237,231	$ 443,730

(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 $8.2 million and $151.6 million for the three months and year ended December 31, 2022 (three months and year ended December 31, 2021 – loss of $44.9 million and $111.7 million).
(3) Includes available credit under Athabasca's Credit Facility and Unsecured Letter of Credit Facility.
(4) The face value of the term debt at December 31, 2022 was US$175 million (December 31, 2021 – US$350 million) translated into Canadian dollars at the December 31, 2022 exchange rate of US$1.00 = C$1.3544 (December 31, 2021 – C$1.2678).

INDEPENDENT RESERVES EVALUATION

The Company's qualified independent reserve evaluators, McDaniel & Associates Consultants Ltd. ("McDaniel"), completed independent reserve evaluations effective December 31, 2022 and 2021. Athabasca's light and medium oil, tight oil, shale gas, conventional natural gas, condensate natural gas liquids and other natural gas liquids reserves are located in the Greater Placid (Montney) and Greater Kaybob (Duvernay) areas within the Company's Light Oil Division. The Company's bitumen reserves are located in the Leismer, Corner and Hangingstone areas of the Company's Thermal Oil Division.

Refer to the "Advisories and Other Guidance" section within this MD&A and the Company's AIF dated March 1, 2023, for further details relating to Athabasca's reserves.

Reserves

At December 31, 2022, the Company had 1,290 MMboe of Proved plus Probable Reserves (December 31, 2021 - 1,301 MMboe). The following table shows the Company's reserves by division (tables may not add due to rounding):

Reserves	December 31, 2022 Proved Developed Producing	December 31, 2022 Proved	December 31, 2022 Proved plus Probable	December 31, 2021 Proved Developed Producing	December 31, 2021 Proved	December 31, 2021 Proved plus Probable
Thermal Oil Division(1)						
Leismer (MMbbl)	35	327	698	41	335	705
Corner (MMbbl)	—	—	353	—	—	353
Hangingstone (MMbbl)	31	76	170	33	79	172
Total Thermal Oil Division (MMbbl)	66	403	1,220	74	414	1,230
Light Oil Division(2)						
Greater Placid (MMboe)	6	22	46	7	20	47
Greater Kaybob (MMboe)	6	7	24	6	7	24
Total Light Oil Division (MMboe)	12	29	70	13	27	72
Consolidated reserves (MMboe)	**78**	**433**	**1,290**	**87**	**441**	**1,301**

(1) Thermal Oil reserves are comprised of bitumen.
(2) Light Oil reserves are comprised of light and medium oil, tight oil, shale gas, conventional natural gas, condensate natural gas liquids and other natural gas liquids.

In the Thermal Oil Division, the Proved Developed Producing (“PDP”) reserves decreased by 11% to 66 MMbbl primarily due to the 2022 production. Proved plus Probable ("2P") reserves were relatively consistent with a 1% decrease to 1,220 MMbbl from 1,230 MMbbl for the year ended December 31, 2022.

In the Light Oil Division, the 2P reserves and 2P Liquids weighting were relatively consistent year-over-year with 70 MMboe 2P reserves (December 31, 2021 - 72 MMboe) and a 57% 2P Liquids weighting (December 31, 2021 - 57%).

BUSINESS ENVIRONMENT

Benchmark prices

(Average)	Three months ended December 31, 2022	2021	Change	Year ended December 31, 2022	2021	Change
Crude oil:						
West Texas Intermediate (WTI) (US$/bbl)(1)	$ 82.65	$ 77.19	7 %	$ 94.23	$ 67.91	39 %
West Texas Intermediate (WTI) (C$/bbl)(1)	$ 112.21	$ 97.25	15 %	$ 122.56	$ 85.11	44 %
Western Canadian Select (WCS) (C$/bbl)(2)	$ 77.36	$ 78.67	(2) %	$ 98.46	$ 68.70	43 %
Edmonton Par (C$/bbl)(3)	$ 110.13	$ 93.14	18 %	$ 120.09	$ 80.09	50 %
Edmonton Condensate (C5+) (C$/bbl)(4)	$ 111.82	$ 99.24	13 %	$ 120.81	$ 84.99	42 %
WCS Differential:						
to WTI (US$/bbl)	$ (25.66)	$ (14.64)	75 %	$ (18.22)	$ (13.04)	40 %
to WTI (C$/bbl)	$ (34.85)	$ (18.58)	88 %	$ (24.10)	$ (16.41)	47 %
Edmonton Par Differential:						
to WTI (US$/bbl)	$ (1.61)	$ (3.10)	(48) %	$ (1.78)	$ (3.88)	(54) %
to WTI (C$/bbl)	$ (2.08)	$ (4.11)	(49) %	$ (2.47)	$ (5.02)	(51) %
Natural gas:						
AECO (C$/GJ)(5)(6)	$ 4.85	$ 4.41	10 %	$ 5.04	$ 3.43	47 %
Foreign exchange:						
USD : CAD	1.3576	1.2599	8 %	1.3006	1.2533	4 %

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 price benchmarks have been supported by improving demand and structural supply deficits. The war in Ukraine has amplified the emphasis on energy security and sanctions have altered energy flows across the globe. Athabasca maintains a constructive outlook on oil prices supported by years of industry underinvestment and demand trends moving higher led by China emerging from COVID restrictions.

Western Canadian Select (“WCS”) differentials temporarily widened through the second half of 2022 as a result of unprecedented US Strategic Petroleum Reserve heavy barrel releases, TC Energy’s Keystone pipeline leak in December 2022, the war in Ukraine impacting global heavy crude oil flows and significant unplanned US refinery outages. Looking to 2023, Athabasca anticipates a strengthening supply-demand picture for heavy barrels as these transient factors pass. The planned start-up of the Trans Mountain pipeline expansion (590,000 bbl/d) in late 2023 and new global heavy oil refining capacity are expected to strengthen WCS prices significantly and reduce overall volatility.

OUTLOOK

2023 Operational & Financial Guidance ($ millions, unless otherwise noted)	Annual
Production (boe/d)(1)	34,500-36,000
% Liquids(1)	93%
Adjusted Funds Flow(1)(2)	$415
Free Cash Flow(1)(2)	$270
Capital Expenditures	$145
Thermal Oil	$120
Light Oil	$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: 2023 US$85 WTI, US$17.50 Western Canadian Select "WCS" heavy differential, C$5 AECO, and $0.75 C$/US$ FX.

Athabasca is maintaining its previously announced 2023 guidance as released December 7, 2022 including a $145 million capital program in 2023 and corporate production of between 34,500-36,000 boe/d. Capital activity will be primarily focused on advancing the expansion project at Leismer.

In 2023, Athabasca plans to allocate a minimum of 75% of Excess Cash Flow (Adjusted Funds Flow less Sustaining Capital) to shareholders. The Company anticipates generating approximately $415 million of Adjusted Funds Flow and approximately $270 million of Free Cash Flow in 2023. As a result of its $3.0 billion in corporate tax pools, Athabasca is not forecasted to pay cash taxes for approximately seven years. Athabasca has excellent exposure to upside in commodity prices with 25% of forecasted 2023 production volumes hedged through collars providing upside to approximately US$110 WTI.

The Board of Directors has approved the filing of an application with the Toronto Stock Exchange ("TSX") for a Normal Course Issuer Bid. Athabasca plans to commence a share buyback program in April, the earliest date permitted under the Company's term debt agreement.

The Company will release its annual ESG update in the Spring of 2023. In 2022, the Company maintained a strong safety record with a 0.08 Total Recordable Injury Frequency with zero reportable hydrocarbon spills. The Company is on track to achieve its stated target of a 30% reduction in emissions intensity by 2025. Athabasca has also partnered with Entropy Inc. to implement carbon capture and storage ("CCS") at Leismer, using Entropy's proprietary CCS technology. This project is expected to be sanctioned in 2023 once government fiscal and regulatory policy for CCS projects are fully in place.

2022 Guidance Review

Production exceeded original guidance with higher than anticipated production from Pad 8 at Leismer, strong facility utilization in Thermal Oil and minimal field downtime in Light Oil. The cashflow metrics guidance was updated throughout the year to reflect realized commodity prices and the outlook for prices for the balance of the year.

2022 Guidance ($ millions, unless otherwise noted)	Original Guidance Dec. 1, 2021	Updated Guidance Feb. 2, 2022	Updated Guidance Jul. 27, 2022	Updated Guidance Nov. 2, 2022	Actual Full year
Production (boe/d)(1)	33,000-34,000	33,000-34,000	34,000-35,000	34,000-35,000	35,262
Adjusted EBITDA(1)(2)	$ 300	$ 350	$ —	$ —	$ 344
Adjusted Funds Flow(1)	$ 250	$ 300	$ 350	$ 330	$ 308
Capital Expenditures	$ 128	$ 128	$ 130	$ 150	$ 147
Free Cash Flow(1)	$ 125	$ 180	$ 220	$ 180	$ 161

(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) Adjusted EBITDA is a non-GAAP measure defined as Net income (loss) and comprehensive income (loss) before financing and interest expense, depletion and depreciation, impairment (reversal) and taxation (recovery) expense adjusted for unrealized foreign exchange gain (loss), unrealized gain (loss) on risk management contracts, gain (loss) on revaluation of provisions and other, gain (loss) on sale of assets, non-cash stock-based compensation and non-cash transportation and marketing.

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 December 31, 2022	2021	Year ended December 31, 2022	2021
PRODUCTION				
Bitumen (bbl/d)	30,210	28,084	28,989	26,805
Oil and condensate (bbl/d)[1]	2,550	3,096	2,848	3,539
Natural gas (Mcf/d)[1]	14,785	18,784	16,169	20,506
Other natural gas liquids (bbl/d)[1]	626	836	730	856
Total (boe/d)[1]	35,850	35,147	35,262	34,618

(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, 2022	2021	Year ended December 31, 2022	2021
Petroleum, natural gas and midstream sales[1]	$ 292,105	$ 305,313	$ 1,557,906	$ 1,061,763
Royalties	(19,957)	(17,972)	(158,742)	(37,717)
Cost of diluent[1]	(128,713)	(105,753)	(548,553)	(360,824)
Operating expenses	(50,767)	(48,562)	(226,630)	(180,831)
Transportation and marketing[2]	(22,349)	(22,378)	(93,686)	(92,038)
Operating Income (Loss)[3]	70,319	110,648	530,295	390,353
Realized gain (loss) on commodity risk management contracts	(8,188)	(44,913)	(151,600)	(111,689)
OPERATING INCOME (LOSS) NET OF REALIZED HEDGING[3]	$ 62,131	$ 65,735	$ 378,695	$ 278,664
REALIZED PRICES[3]				
Heavy oil (Blended bitumen) ($/bbl)[3]	$ 72.24	$ 75.65	$ 94.15	$ 66.30
Oil and condensate ($/bbl)[3]	108.33	93.33	118.27	79.10
Natural gas ($/Mcf)[3]	5.48	5.29	5.73	4.03
Other natural gas liquids ($/bbl)[3]	60.52	58.60	69.57	49.29
Realized price (net of cost of diluent) ($/boe)[3]	53.84	63.89	79.28	55.67
Royalties ($/boe)[3]	(6.58)	(5.75)	(12.47)	(3.00)
Operating expenses ($/boe)[3]	(16.73)	(15.55)	(17.80)	(14.36)
Transportation and marketing ($/boe)[3]	(7.36)	(7.16)	(7.36)	(7.31)
Operating Netback ($/boe)[3]	23.17	35.43	41.65	31.00
Realized gain (loss) on commodity risk mgmt. contracts ($/boe)[3]	(2.70)	(14.38)	(11.91)	(8.87)
OPERATING NETBACK NET OF REALIZED HEDGING ($/boe)[3]	$ 20.47	$ 21.05	$ 29.74	$ 22.13

(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 $2.2 million for the three months and year ended December 31, 2022 (three months and year ended December 31, 2021 - $0.6 million and $1.5 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 December 31, 2022	2021	Year ended December 31, 2022	2021
Operating Income (Loss) Net of Realized Hedging[1]	$ 62,131	$ 65,735	$ 378,695	$ 278,664
Non-cash transportation and marketing	(558)	(558)	(2,230)	(1,487)
Unrealized gain (loss) on commodity risk management contracts	(4,175)	28,515	27,261	(34,083)
Impairment reversal (expense)	80,000	345,700	80,000	345,700
Depletion and depreciation	(29,512)	(24,296)	(116,641)	(95,673)
Gain (loss) on sale of assets	37	23	440	20,123
Exploration expenses	(630)	(430)	(3,117)	(2,824)
CONSOLIDATED SEGMENTS INCOME (LOSS)	$ 107,293	$ 414,689	$ 364,408	$ 510,420

(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 December 31, 2022	2021	Year ended December 31, 2022	2021
Thermal Oil Division	$ 10,895	$ 12,355	$ 110,582	$ 81,985
Light Oil Division	1,594	5,291	11,662	6,931
Corporate assets	540	706	25,205	3,226
CAPITAL EXPENDITURES[(1)(2)(3)]	$ 13,029	$ 18,352	$ 147,449	$ 92,142

(1) For the three months and year ended December 31, 2022, expenditures include capitalized cash based stock-based compensation costs of $0.4 million and $3.0 million (three months and year ended December 31, 2021 - $0.7 million and $3.2 million).

(2) For the three months and year ended December 31, 2022, expenditures include capitalized staff costs of $1.8 million and $7.2 million (three months and year ended December 31, 2021 - $1.5 million and $6.3 million).

(3) Excludes non-cash capitalized stock-based compensation and non-cash capitalized decommissioning obligation asset costs.

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 have 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 July 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.

Leisma Operating Results

	Three months ended December 31, 2022	2021	Year ended December 31, 2022	2021
VOLUMES				
Bitumen production (bbl/d)	21,774	18,794	20,135	17,707
Bitumen sales (bbl/d)	20,469	18,348	19,884	17,623
Heavy oil (blended bitumen) sales (bbl/d)	28,850	25,840	27,867	24,670

($ Thousands, unless otherwise noted)	Three months ended December 31, 2022	2021	Year ended December 31, 2022	2021
Heavy oil (blended bitumen) sales	$ 190,692	$ 179,195	$ 946,609	$ 597,343
Cost of diluent	(97,665)	(70,902)	(378,427)	(231,383)
Total bitumen sales	93,027	108,293	568,182	365,960
Royalties	(9,785)	(9,699)	(92,094)	(18,834)
Operating expenses - non-energy	(12,864)	(13,107)	(56,798)	(47,635)
Operating expenses - energy	(17,470)	(14,647)	(68,219)	(49,621)
Transportation and marketing	(12,613)	(11,807)	(50,663)	(47,778)
LEISMER OPERATING INCOME (LOSS)(1)	$ 40,295	$ 59,033	$ 300,408	$ 202,092
REALIZED PRICE(1)				
Heavy oil (blended bitumen) sales ($/bbl)(1)	$ 71.84	$ 75.38	$ 93.06	$ 66.34
Bitumen sales ($/bbl)(1)	$ 49.40	$ 64.15	$ 78.29	$ 56.89
Royalties ($/bbl)(1)	(5.20)	(5.75)	(12.69)	(2.93)
Operating expenses - non-energy ($/bbl)(1)	(6.83)	(7.76)	(7.83)	(7.41)
Operating expenses - energy ($/bbl)(1)	(9.28)	(8.68)	(9.40)	(7.71)
Transportation and marketing ($/bbl)(1)	(6.70)	(6.99)	(6.98)	(7.43)
LEISMER OPERATING NETBACK ($/bbl)(1)	$ 21.39	$ 34.97	$ 41.39	$ 31.41

(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, 2022, was 21,774 bbl/d and 20,135 bbl/d, an increase of 16% and 14%, respectively, compared to the corresponding periods in 2021. Production increases are primarily attributed to the ramp-up of Pad 8 (five sustaining well pairs) through 2022.

Leismer's Operating Netback was $21.39/bbl for the three months ended December 31, 2022, representing a decrease of $13.58/bbl, compared with the same period in 2021. The decrease is primarily due to lower WCS benchmark oil prices and higher energy operating expenses. For the year ended December 31, 2022 Leismer's Operating Netback was $41.39/bbl, representing an increase of $9.98/bbl, compared with the same period in 2021. The increase is primarily due to higher WCS benchmark oil prices, partially offset by higher royalties and operating costs.

Government and contingent bitumen royalties increased for the year 2022 due to higher oil prices.

Total operating expenses were $16.11/bbl in the fourth quarter of 2022 and $17.23/bbl for the year ended December 31, 2022, compared to $16.44/bbl and $15.12/bbl, respectively, in the comparable periods of 2021.

Energy operating costs increased as a result of higher natural gas and electricity prices, partially offsetting this increase are the corporate AECO fixed price swap purchase contracts that resulted in a total Thermal Oil realized gain of $1.9 million during the fourth quarter of 2022 and $9.3 million for the year ended December 31, 2022 (three months and year ended December 31, 2021 - $1.5 million and $2.6 million).

Hangingstone Operating Results

	Three months ended December 31, 2022	2021	Year ended December 31, 2022	2021
VOLUMES				
Bitumen production (bbl/d)	8,436	9,290	8,854	9,098
Bitumen sales (bbl/d)	6,877	8,541	8,725	9,057
Heavy oil (blended bitumen) sales (bbl/d)	9,632	12,245	12,365	13,099

($ Thousands, unless otherwise noted)	Three months ended December 31, 2022	2021	Year ended December 31, 2022	2021
Heavy oil (blended bitumen) and midstream sales	$ 65,057	$ 85,881	$ 436,018	$ 316,715
Cost of diluent	$ (31,048)	$ (34,851)	$ (170,126)	$ (129,441)
Total bitumen and midstream sales	34,009	51,030	265,892	187,274
Royalties	(3,471)	(4,390)	(41,040)	(8,723)
Operating expenses - non-energy	(4,198)	(5,249)	(24,521)	(20,882)
Operating expenses - energy	(8,444)	(9,642)	(46,403)	(38,298)
Transportation and marketing[1]	(7,500)	(8,053)	(33,825)	(34,202)
HANGINGSTONE OPERATING INCOME (LOSS)[2]	$ 10,396	$ 23,696	$ 120,103	$ 85,169
REALIZED PRICE[2]				
Heavy oil (blended bitumen) and midstream sales ($/bbl)[2]	$ 73.41	$ 76.23	$ 96.61	$ 66.24
Bitumen and midstream sales ($/bbl)[2]	$ 53.75	$ 64.94	$ 83.49	$ 56.65
Royalties ($/bbl)[2]	(5.49)	(5.59)	(12.89)	(2.64)
Operating expenses - non-energy ($/bbl)[2]	(6.64)	(6.68)	(7.70)	(6.32)
Operating expenses - energy ($/bbl)[2]	(13.35)	(12.27)	(14.57)	(11.59)
Transportation and marketing ($/bbl)[2]	(11.85)	(10.25)	(10.62)	(10.35)
HANGINGSTONE OPERATING NETBACK ($/bbl)[2]	$ 16.42	$ 30.15	$ 37.71	$ 25.75

(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, 2022 (three months and year ended December 31, 2021 - $0.6 million and $1.5 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 months and year ended December 31, 2022 decreased as a result of natural declines.

The Hangingstone Operating Netback was $16.42/bbl for the three months ended December 31, 2022, representing a decrease of $13.73/bbl, compared with the same period in 2021. The decrease is primarily due to lower WCS benchmark oil prices and higher energy operating costs. For the year ended December 31, 2022 the Hangingstone Operating Netback was $37.71/bbl, representing an increase of $11.96/bbl, compared with the same period in 2021. The increase is primarily due to higher WCS benchmark oil prices, partially offset by higher royalties and operating costs.

Government and contingent bitumen royalties increased for the year 2022 due to higher oil prices.

Total operating expenses were $19.99/bbl in the fourth quarter of 2022 and $22.27/bbl for the year ended December 31, 2022, compared to $18.95/bbl and $17.91/bbl, respectively, in the comparable periods of 2021.

Energy operating costs increased as a result of higher natural gas and electricity prices, partially offsetting this increase are the corporate AECO fixed price swap purchase contracts that resulted in a total Thermal Oil realized gain of $1.9 million during the fourth quarter of 2022 and $9.3 million for the year ended December 31, 2022 (three months and year ended December 31, 2021 - $1.5 million and $2.6 million). The increase in the Hangingstone energy operating costs were partially offset by a 12% reduction in the steam to oil ratio year over year.

Consolidated Thermal Oil Operating Results

	Three months ended December 31, 2022	2021	Year ended December 31, 2022	2021
VOLUMES				
Bitumen production (bbl/d)	30,210	28,084	28,989	26,805
Bitumen sales (bbl/d)	27,346	26,889	28,609	26,680
Heavy oil (blended bitumen) sales (bbl/d)	38,482	38,085	40,232	37,769

($ Thousands, unless otherwise noted)	Three months ended December 31, 2022	2021	Year ended December 31, 2022	2021
Heavy oil (blended bitumen) and midstream sales	$ 255,749	$ 265,076	$ 1,382,627	$ 914,058
Cost of diluent	(128,713)	(105,753)	(548,553)	(360,824)
Total bitumen and midstream sales	127,036	159,323	834,074	553,234
Royalties	(13,256)	(14,089)	(133,134)	(27,557)
Operating expenses - non-energy	(17,062)	(18,356)	(81,319)	(68,517)
Operating expenses - energy	(25,914)	(24,289)	(114,622)	(87,919)
Transportation and marketing(1)	(20,113)	(19,860)	(84,488)	(81,980)
THERMAL OIL OPERATING INCOME (LOSS)(2)	$ 50,691	$ 82,729	$ 420,511	$ 287,261
REALIZED PRICE(2)				
Heavy oil (blended bitumen) and midstream sales ($/bbl)(2)	$ 72.24	$ 75.65	$ 94.15	$ 66.30
Bitumen and midstream sales ($/bbl)(2)	$ 50.49	$ 64.40	$ 79.87	$ 56.81
Royalties ($/bbl)(2)	(5.27)	(5.70)	(12.75)	(2.83)
Operating expenses - non-energy ($/bbl)(2)	(6.78)	(7.42)	(7.79)	(7.04)
Operating expenses - energy ($/bbl)(2)	(10.30)	(9.82)	(10.98)	(9.03)
Transportation and marketing ($/bbl)(2)	(7.99)	(8.03)	(8.09)	(8.42)
THERMAL OIL OPERATING NETBACK ($/bbl)(2)	$ 20.15	$ 33.43	$ 40.26	$ 29.49

(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, 2022 (three months and year ended December 31, 2021 - $0.6 million and $1.5 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 December 31, 2022	2021	Year ended December 31, 2022	2021
Thermal Oil Operating Income (Loss)(1)	$ 50,691	$ 82,729	$ 420,511	$ 287,261
Non-cash transportation and marketing	(558)	(558)	(2,230)	(1,487)
Impairment reversal (expense)	—	272,800	—	272,800
Depletion and depreciation	(19,464)	(13,438)	(75,299)	(48,309)
Gain (loss) on sale of assets	37	23	440	20,023
Exploration expenses	(630)	(430)	(3,117)	(2,824)
THERMAL OIL SEGMENT INCOME (LOSS)	$ 30,076	$ 341,126	$ 340,305	$ 527,464

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

In the fourth quarter of 2021 Athabasca reversed previously recognized impairment losses of $272.8 million as the Hangingstone CGU was fully operational, commodity price forecasts had significantly increased and the Company had completed its debt refinancing. In the fourth quarter of 2022 Athabasca identified a mix of indicators of impairment and impairment reversal within the Hangingstone CGU which included the increase in forecasted commodity prices, increasing interest rates and changes to the regulatory environment. The Hangingstone impairment test resulted in supporting the assets carrying value.

Depletion and depreciation increased $6.0 million and $27.0 million during the three months and year ended December 31, 2022, compared to the same periods in the prior year primarily due to the higher depletable cost base at Hangingstone as a result of the December 31, 2021 impairment reversal and higher production volumes at Leismer.

In 2021, Athabasca recorded a gain of $19.7 million, net of transaction costs, on the sale of its 20,000 bbl/d Trans Mountain Expansion Project pipeline service.

Thermal Oil Capital Expenditures

($ Thousands)	Three months ended December 31, 2022	Three months ended December 31, 2021	Year ended December 31, 2022	Year ended December 31, 2021
Leismer Project	$ 9,020	$ 10,357	$ 102,668	$ 74,689
Hangingstone Project	1,740	1,925	7,457	7,024
Other Thermal Oil exploration	135	73	457	272
THERMAL OIL CAPITAL EXPENDITURES(1)	$ 10,895	$ 12,355	$ 110,582	$ 81,985

(1) For the three months and year ended December 31, 2022, capital expenditures include $1.4 million and $5.5 million of capitalized staff costs (three months and year ended December 31, 2021 - $1.0 million and $4.1 million).

Thermal Oil capital expenditures for the year ended December 31, 2022 of $110.6 million were primarily related to sustaining operations and a planned facility turnaround at Leismer, along with routine pump replacements across both assets. At Leismer, the Company converted five Pad 8 wells to production, two Pad 6 infill wells were placed on production and rig released the Pad 8 expansion (five additional well pairs).

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 December 31, 2022	2021	Year ended December 31, 2022	2021
PRODUCTION[(1)]				
Oil and condensate (bbl/d)	2,550	3,096	2,848	3,539
Natural gas (Mcf/d)	14,785	18,784	16,169	20,506
Other natural gas liquids (bbl/d)	626	836	730	856
Total (boe/d)	5,640	7,063	6,273	7,813
Consisting of:				
Greater Placid area (boe/d)	2,913	3,902	3,232	4,310
% Liquids	41%	44%	42%	44%
Greater Kaybob area (boe/d)	2,727	3,161	3,041	3,503
% Liquids	72%	70%	72%	72%

(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, 2022	2021	Year ended December 31, 2022	2021
Petroleum and natural gas sales	$ 36,356	$ 40,237	$ 175,279	$ 147,705
Royalties	(6,701)	(3,883)	(25,608)	(10,160)
Operating expenses	(7,791)	(5,917)	(30,689)	(24,395)
Transportation and marketing	(2,236)	(2,518)	(9,198)	(10,058)
LIGHT OIL OPERATING INCOME (LOSS)[(1)]	$ 19,628	$ 27,919	$ 109,784	$ 103,092
REALIZED PRICES[(1)]				
Oil and condensate ($/bbl)[(1)]	$ 108.33	$ 93.33	$ 118.27	$ 79.10
Natural gas ($/Mcf)[(1)]	5.48	5.29	5.73	4.03
Other natural gas liquids ($/bbl)[(1)]	60.52	58.60	69.57	49.29
Realized price ($/boe)[(1)]	70.07	61.92	76.55	51.79
Royalties ($/boe)[(1)]	(12.91)	(5.98)	(11.18)	(3.56)
Operating expenses ($/boe)[(1)]	(15.02)	(9.11)	(13.40)	(8.55)
Transportation and marketing ($/boe)[(1)]	(4.31)	(3.88)	(4.02)	(3.53)
LIGHT OIL OPERATING NETBACK ($/boe)[(1)]	$ 37.83	$ 42.95	$ 47.95	$ 36.15

(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 months and year ended December 31, 2022 decreased as a result of natural declines, partially offset by three gross Greater Kaybob wells that were placed on production during the first quarter of 2022.

The Operating Netback was $37.83/boe for the three months ended December 31, 2022, representing a decrease of $5.12/boe, compared with the same period in 2021. The decrease is primarily due to higher royalties and operating expenses, partially offset by stronger commodity prices. The Operating Netback was $47.95/boe for the year ended December 31, 2022, representing an increase of $11.80/boe, compared with the same period in 2021. The increase is primarily due to stronger commodity prices, partially offset by higher royalties and operating expenses.

The rise in royalties for both the fourth quarter and the year ended December 31, 2022 is due to stronger commodity prices and wells coming off government royalty incentive programs.

Operating expenses on a per boe basis increased as a result of lower production volumes, and higher third party processing fees and power costs.

Light Oil Segment Income (Loss)

($ Thousands)	Three months ended December 31, 2022	2021	Year ended December 31, 2022	2021
Light Oil Operating Income (Loss)(1)	$ 19,628	$ 27,919	$ 109,784	$ 103,092
Impairment reversal (expense)	80,000	72,900	80,000	72,900
Depletion and depreciation	(10,048)	(10,858)	(41,342)	(47,364)
Gain (loss) on sale of assets	—	—	—	100
LIGHT OIL SEGMENT INCOME (LOSS)	$ 89,580	$ 89,961	$ 148,442	$ 128,728

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

In the fourth quarter of 2021 Athabasca reversed previous Light Oil impairments of $72.9 million as a result of higher commodity price forecasts and the Company completing its debt refinancing. In the fourth quarter of 2022 Athabasca again completed an impairment test on the Light Oil CGU due to higher commodity price forecasts and increasing interest rates, resulting in the reversal of previous Light Oil impairments of $80.0 million.

Depletion and depreciation decreased $0.8 million and $6.0 million during the three months and year ended December 31, 2022, compared to the same periods in the prior year primarily due to lower production volumes.

Light Oil Capital Expenditures

($ Thousands)	Three months ended December 31, 2022	2021	Year ended December 31, 2022	2021
Greater Placid	$ 1,216	$ 854	$ 3,273	$ 3,260
Greater Kaybob	378	4,437	8,389	3,671
LIGHT OIL CAPITAL EXPENDITURES(1)	$ 1,594	$ 5,291	$ 11,662	$ 6,931

(1) For the three months and year ended December 31, 2022, capital expenditures include $0.4 million and $1.7 million of capitalized staff costs (three months and year ended December 31, 2021 - $0.5 million and $2.2 million).

For the year ended December 31 2022, Light Oil capital expenditures were primarily incurred at Greater Kaybob for the completion and infrastructure work for three gross wells drilled in 2019 and in the second quarter of 2022 the Company successfully completed two facility turnarounds at Kaybob West and Kaybob East.

The following table summarizes Athabasca's well activity for the three months and year ended December 31, 2022 and 2021:

	Three months ended December 31,				Year ended December 31,			
	2022		2021		2022		2021	
Well activity(1)	Gross	Net	Gross	Net	Gross	Net	Gross	Net
GREATER PLACID								
Wells drilled	—	—	—	—	—	—	—	—
Wells completed	—	—	—	—	—	—	—	—
Wells brought on production	—	—	—	—	—	—	—	—
GREATER KAYBOB								
Wells drilled	—	—	—	—	—	—	—	—
Wells completed	—	—	—	—	3	0.9	—	—
Wells brought on production	—	—	—	—	3	0.9	—	—

(1) Drilling counts are based on rig release date and brought on production counts are based on first production date of in-line test or tie-in to permanent facilities.

CORPORATE REVIEW

Liquidity and Capital Resources

Funding

Athabasca is a low leveraged company that generates significant Free Cash Flow through its low-decline, oil weighted asset base at current commodity prices. For 2023, it is anticipated that Athabasca's capital and operating activities will be funded through cash flow from operating activities and existing cash and cash equivalents. The Company is intending to direct a portion of its 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 December 31, 2022, Athabasca had Liquidity of $285.3 million which included $197.5 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 December 31, 2022:

Term Debt

On October 22, 2021, Athabasca closed a private placement offering (the "Offering") of 350,000 units for gross cash proceeds of US$339.5 million. Each unit consisted of US$1,000 principal amount of senior secured second lien notes (US$350 million original principal) due November 1, 2026 (each "2026 Note") which bear interest at 9.75% per annum, and one five-year warrant (each "Warrant") to purchase 227 common shares at an exercise price of $0.9441 per common share issuable.

Up until an aggregate amount of US$175 million principal has been redeemed, the Company must direct at least 75% of Free Cash Flow ("FCF") towards the redemption of the 2026 Notes at a cash price equal to 105% of the principal, plus accrued and unpaid interest. The redemption dates are semiannual with the October to March (Q4 – Q1) FCF redemption payable in May and the April to September (Q2 – Q3) FCF redemption payable in November. Athabasca may also 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.

As at December 31, 2022, the principal balance was $237.2 million (US$175.2 million). In 2022, the Company has redeemed a total of $227.3 million (US$174.8 million) of principal through open market purchases, equity redemptions through warrant proceeds and the FCF payment feature within the indenture.

Credit Facility

In the third quarter of 2022, Athabasca renewed its $110.0 million reserve-based credit facility (the "Credit Facility"). The Credit Facility is a 364 day committed facility available on a revolving basis until October 21, 2023, 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 October 21, 2024. The Credit Facility is subject to a semi-annual borrowing base review, occurring approximately in April and September 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, 2022 and December 31, 2021, 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 and is supported by a performance security guarantee from Export Development Canada (December 31, 2021 - $50 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 December 31, 2022, the Company had $47.8 million of letters of credit outstanding under the Unsecured Letter of Credit Facility (December 31, 2021 - $47.8 million).

Financing and Interest

($ Thousands)	Three months ended December 31, 2022	2021	Year ended December 31, 2022	2021
Financing and interest expense on indebtedness	$ 10,012	$ 15,570	$ 49,744	$ 59,151
Financing fees expense - warrant issuance costs allocation	—	1,488	—	1,488
Accretion of 2022 Notes	—	4,917	—	13,442
Accretion of 2026 Notes	9,201	3,366	28,334	3,366
Accretion of warrants	85	153	2,605	153
Accretion of provisions	2,644	3,656	10,519	14,007
Interest expense on lease liability	197	275	909	1,209
TOTAL FINANCING AND INTEREST	$ 22,139	$ 29,425	$ 92,111	$ 92,816

During the three months and year ended December 31, 2022 and 2021, total financing and interest expenses were primarily attributable to the financing, interest and accretion expenses related to the Company's Notes.

Foreign Exchange Gain (Loss), Net

($ Thousands)	Three months ended December 31, 2022	2021	Year ended December 31, 2022	2021
Unrealized foreign exchange gain (loss)	$ 3,523	$ (33,045)	$ (900)	$ (25,637)
Realized foreign exchange gain (loss)	(3,616)	34,713	(3,991)	33,063
FOREIGN EXCHANGE GAIN (LOSS), NET	$ (93)	$ 1,668	$ (4,891)	$ 7,426

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. The 2021 realized foreign exchange gain includes a $28.6 million realized foreign exchange gain on the 2022 US dollar Notes redemption on November 6, 2021 and a $4.3 million realized foreign exchange gain on US dollar cash balances held in escrow during the notes refinancing closing period.

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, 2022, 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	January - March 2023	13,750 bbl/d	$ 70.92 - 155.76	$ 52.36 - 115.00
Purchase contracts			*C$/GJ*	*US$/GJ*
AECO fixed price swaps	January - December 2023	20,000 GJ/d	$ 4.90	$ 3.62

(1) The implied C$ or US$ Average Price per bbl or GJ, as applicable, was calculated using the December 31, 2022 exchange rate of US$1.00 = C$1.3544.

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 December 31, 2022, the pricing derivative had an asset value of $0.8 million (December 31, 2021 - $nil).

The following table summarizes the Company's net gain (loss) on commodity risk management contracts for the three months and year ended December 31, 2022 and 2021:

($ Thousands)	Three months ended December 31, 2022	2021	Year ended December 31, 2022	2021
Unrealized gain (loss) on commodity risk mgmt. contracts	$ (4,175)	$ 28,515	$ 27,261	$ (34,083)
Realized gain (loss) on commodity risk mgmt. contracts	(8,188)	(44,913)	(151,600)	(111,689)
GAIN (LOSS) ON COMMODITY RISK MGMT. CONTRACTS, NET	$ (12,363)	$ (16,398)	$ (124,339)	$ (145,772)

At December 31, 2022, 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 commodity risk management contracts:

As at December 31, 2022	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	$ 6,946	$ (6,946)

Additional financial commodity risk management has taken place subsequent to December 31, 2022 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	January - March 2023	6,350 bbl/d	$ 67.72 - 132.75	$ 50.00 - 98.01
WTI collar	April - June 2023	10,000 bbl/d	$ 67.72 - 149.09	$ 50.00 - 110.08
WTI collar	July - September 2023	2,500 bbl/d	$ 67.72 - 147.74	$ 50.00 - 109.08

(1) The implied C$ or US$ Average Price per bbl or GJ, as applicable, was calculated using the December 31, 2022 exchange rate of US$1.00 = C$1.3544.

Commitments and Contingencies

The following table summarizes Athabasca's estimated future unrecognized minimum commitments as at December 31, 2022 for the following five years and thereafter:

($ Thousands)	2023	2024	2025	2026	2027	Thereafter	Total
Transportation and processing(1)	$ 118,328	$ 113,257	$ 109,369	$ 108,802	$ 105,292	$ 1,051,172	$ 1,606,220
Interest expense on term debt(1)	23,130	23,130	23,130	19,275	—	—	88,665
Purchase commitments and other(1)	44,812	—	—	—	—	—	44,812
TOTAL COMMITMENTS	$ 186,270	$ 136,387	$ 132,499	$ 128,077	$ 105,292	$ 1,051,172	$ 1,739,697

(1) Commitments which are denominated in US dollars were translated into Canadian dollars at the December 31, 2022 exchange rate of US$1.00 = C$1.3544.

The Company is, from time to time, involved in claims arising in the normal course of business. The Company is currently undergoing income 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 and joint interest partners and risk management contract counterparties.

As at	December 31, 2022	December 31, 2021
Petroleum and natural gas receivables	$ 85,432	$ 85,817
Joint interest billings	4,009	2,646
Risk management (realized), government and other receivables	44	364
TOTAL	$ 89,485	$ 88,827

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, 2022. 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 December 31, 2022 of $197.5 million (December 31, 2021 - $223.1 million), from a 1.0% change in interest rates, would have an annualized impact of approximately $2.0 million (year ended December 31, 2021 - $2.2 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 December 31, 2022	2021	Year ended December 31, 2022	2021
TOTAL GENERAL AND ADMINISTRATIVE	$ 6,024	$ 4,499	$ 20,768	$ 15,946
G&A per boe[1]	$ 1.83	$ 1.39	$ 1.61	$ 1.26

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

During the three months and year ended December 31, 2022, Athabasca's G&A expenses and G&A per boe increased compared to the same periods in the prior year primarily due to increased staffing levels and higher salaries and benefits.

Stock Based Compensation

During the three months and year ended December 31, 2022, Athabasca's stock-based compensation expense was $6.2 million and $27.4 million, respectively, compared to $5.2 million and $17.3 million in the respective prior year periods. The increase in 2022 is primarily due to the increase in the fair value of the cash settled stock-based compensation plans as a result of the share price increasing in 2022.

Gain (Loss) on Revaluation of Provisions and Other

($ Thousands)	Three months ended December 31, 2022	2021	Year ended December 31, 2022	2021
Change in fair value of warrant liability	$ (7,697)	$ (14,768)	$ (68,930)	$ (14,768)
Change in estimated decommissioning obligations related to fully impaired E&E assets	9,672	22,053	6,599	22,053
Provision for pipeline project	-	-	-	60,564
Other	515	151	1,742	151
TOTAL GAIN (LOSS) ON REVALUATION OF PROVISIONS AND OTHER	$ 2,490	$ 7,436	$ (60,589)	$ 68,000

The warrants are classified as a financial liability due to the cashless exercise provision therefore they have to be revalued quarterly. The changes in the fair value of the warrant liability in 2022 primarily relate to changes in the share price.

In the third quarter of 2021, Athabasca assigned its 7,200 bbl/d Keystone base service from Hardisty to the US Gulf Coast and the Development Cost Agreement ("DCA") in relation to the Keystone XL pipeline to an industry counterparty resulting in a gain on the derecognition of the US$48 million ($60.6 million) DCA provision.

Income Taxes

When factoring in updated commodity price forecasts at December 31, 2022 management has determined the Company will be able to utilize the previously unrecognized tax assets against taxable profits. At December 31, 2022, Athabasca has recognized a deferred tax asset of $413.3 million (December 31, 2021 - nil). The Company has approximately $3.0 billion in tax pools, including approximately $2.3 billion in non-capital losses and exploration tax pools available for immediate deduction against future income. Athabasca's material non-capital losses have an expiry profile between 2030 and 2041.

From time to time, Athabasca undergoes income tax audits in the normal course of business. The Company has received a notice of reassessment from the Canada Revenue Agency ("CRA”) and Alberta Finance. While the final outcome of the reassessment cannot be predicted with certainty, Athabasca has received legal advice that confirms its position as filed and believes it is likely to be successful in appealing the reassessment. As such, the Company has not recognized any provision in its Consolidated Financial Statements with respect to the reassessment and previously posted a $12.6 million deposit with the CRA while objecting the reassessment.

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.

Uncertainty around timing of future pipeline infrastructure due to regulatory, judicial and legislative delays is a significant risk to Athabasca and could have a material impact on future financial results. Additional information is available in Athabasca’s AIF that is filed on the Company’s SEDAR profile at www.sedar.com.

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, 2022, there were 586.5 million common shares outstanding, an aggregate of 20.7 million restricted share units and performance share units outstanding, 7.2 million stock options outstanding and 31.6 million potential shares issuable under warrants agreements (139,217 warrants outstanding). During the year ended December 31, 2022, Athabasca issued 11.4 million common shares in respect of the Company’s equity-settled share-based compensation plans and 44.2 million common shares from warrant exercises.

As at February 28, 2023, there were 586.7 million common shares outstanding, an aggregate of 20.7 million restricted share units and performance share units outstanding, 7.0 million stock options outstanding and 31.6 million potential shares issuable under warrants agreements (139,217 warrants outstanding).

SUMMARY OF QUARTERLY RESULTS

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

	2022				2021			
($ Thousands, unless otherwise noted)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	82.65	91.55	108.41	94.29	77.19	70.56	66.07	57.84
WTI (C$/bbl)	112.21	119.54	138.39	119.38	97.25	88.91	81.11	73.24
Western Canadian Select (C$/bbl)	77.36	93.48	122.04	100.96	78.67	71.77	66.96	57.40
Edmonton Par (C$/bbl)	110.13	116.79	137.83	115.62	93.14	83.70	77.07	66.44
Edmonton Condensate (C5+) (C$/bbl)	111.82	112.87	137.70	120.84	99.24	86.78	81.00	72.92
AECO (C$/GJ)	4.85	3.95	6.86	4.49	4.41	3.41	2.93	2.98
Foreign exchange (USD : CAD)	1.36	1.31	1.28	1.27	1.26	1.26	1.23	1.27
CONSOLIDATED								
Petroleum and natural gas production (boe/d)(1)	35,850	37,240	33,247	34,679	35,147	34,255	34,659	34,401
Realized price (net of cost of diluent) ($/boe)(1)	53.84	75.10	105.99	83.53	63.89	60.40	53.76	44.23
Petroleum, natural gas and midstream sales ($)(2)	292,105	406,794	453,618	405,389	305,313	291,300	243,868	221,282
Operating Income (Loss) ($)(1)	70,319	140,081	169,255	150,640	110,648	120,581	93,196	65,928
Operating Income (Loss) Net of Realized Hedging ($)(1)	62,131	110,021	103,549	102,994	65,735	92,742	75,372	44,815
Operating Netback ($/boe)(1)	23.17	39.17	57.51	47.40	35.43	36.02	31.09	21.12
Operating Netback Net of Realized Hedging ($/boe)(1)	20.47	30.76	35.18	32.41	21.05	27.70	25.14	14.36
Capital expenditures ($)	13,029	52,300	51,191	30,929	18,352	15,608	22,628	35,554
THERMAL OIL DIVISION								
Bitumen production (bbl/d)	30,210	31,023	26,768	27,909	28,084	26,729	26,433	25,949
Bitumen sales volumes (bbl/d)	27,346	32,650	25,863	28,545	26,889	28,852	24,710	26,240
Realized bitumen price ($/bbl)(1)	50.49	76.09	109.67	85.78	64.40	62.39	55.49	43.83
Heavy Oil (blended bitumen) and midstream sales ($)	255,749	366,804	399,793	360,281	265,076	254,769	207,503	186,710
Operating Income (Loss) ($)(1)	50,691	117,916	131,067	120,837	82,729	94,796	67,568	42,168
Operating Netback ($/bbl)(1)	20.15	39.25	55.68	47.04	33.43	35.71	30.05	17.85
Capital expenditures ($)	10,895	35,412	43,093	21,182	12,355	15,228	21,388	33,014
LIGHT OIL DIVISION								
Petroleum and natural gas production (boe/d)(1)	5,640	6,217	6,479	6,770	7,063	7,526	8,226	8,452
Realized price ($/boe)(1)	70.07	69.92	91.29	74.03	61.92	52.76	48.58	45.45
Petroleum and natural gas sales ($)(2)	36,356	39,990	53,825	45,108	40,237	36,531	36,365	34,572
Operating Income (Loss) ($)(1)	19,628	22,165	38,188	29,803	27,919	25,785	25,628	23,760
Operating Netback ($/boe)(1)	37.83	38.76	64.77	48.92	42.95	37.25	34.23	31.24
Capital expenditures ($)	1,594	860	1,221	7,987	5,291	128	544	968
OPERATING RESULTS								
Cash flow from operating activities ($)	69,368	117,853	68,535	59,862	81,189	75,743	36,183	1,138
Adjusted Funds Flow ($)(1)	46,074	102,370	84,799	74,761	42,643	72,233	50,228	18,961
Net income (loss) ($)	489,654	155,097	47,121	(119,601)	384,073	104,951	(13,944)	(17,472)
Net income (loss) per share - basic ($)	0.83	0.27	0.08	(0.23)	0.72	0.20	(0.03)	(0.03)
BALANCE SHEET ITEMS								
Cash and cash equivalents ($)	197,525	200,100	154,172	213,534	223,056	273,989	152,639	141,130
Restricted cash ($)	—	—	—	—	—	46,107	90,232	135,120
Total assets ($)	2,230,354	1,803,624	1,815,390	1,814,662	1,742,131	1,510,924	1,466,102	1,443,246
Term debt ($)(3)	206,133	240,078	250,756	355,328	384,298	568,428	549,855	555,160
Shareholders' equity ($)	1,710,497	1,218,174	1,057,355	909,852	1,025,959	640,542	534,330	547,035

(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.

SELECTED ANNUAL INFORMATION

The following table provides a summary of selected annual information for the years ended 2022, 2021 and 2020:

($ Thousands, unless otherwise noted)	December 31, 2022	December 31, 2021	December 31, 2020
Petroleum and natural gas production (boe/d)[1]	35,262	34,618	32,483
Petroleum, natural gas and midstream sales	$ 1,504,685	$ 1,016,323	$ 464,648
Net income (loss) and comprehensive income (loss)	$ 572,271	$ 457,608	$ (657,525)
per share (basic)	$ 1.01	$ 0.86	$ (1.24)
Cash flow from operating activities	$ 315,618	$ 194,253	$ (22,910)
per share (basic)	$ 0.56	$ 0.37	$ (0.04)
Adjusted Funds Flow[1]	$ 308,004	$ 184,065	$ (18,727)
per share (basic)	$ 0.54	$ 0.35	$ (0.04)
Capital expenditures	$ 147,449	$ 92,142	$ 111,640
Capital Expenditures Net of Capital-Carry[1]	$ 147,449	$ 92,142	$ 88,900
Total assets	$ 2,230,354	$ 1,742,131	$ 1,425,984
Face value of term debt[2]	$ 237,231	$ 443,730	$ 572,940
Weighted average shares outstanding (basic)	568,035,589	530,692,724	528,837,646
Weighted average shares outstanding (diluted)	586,913,328	546,717,181	528,837,646

(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) The face value of the term debt at December 31, 2022 is US$175 million (December 31, 2021 - US$350 million; December 31, 2020 - US$450 million) and was translated into Canadian dollars at the December 31, 2022 exchange rate of US$1.00 = C$1.3544 (December 31, 2021 - C$1.2678; December 31, 2020 - C$1.2732).

ACCOUNTING POLICIES AND ESTIMATES

During the year ended December 31, 2022 and 2021, 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 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).

Significant Accounting Estimates and Judgments

For the year ended December 31, 2022, Athabasca's significant estimates and judgments are as follows:

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).

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, 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 Company evaluates the carrying value of its inventory at the lower of cost and net realizable value. The net realizable value is estimated based on anticipated current market prices that Athabasca would expect to receive from the sale of its inventory.

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.

The lease liability is based upon assumptions including the identification of fixed lease payments, separating lease components from non-lease components and the incremental borrowing rate.

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) in the period in which the change occurs. Tax provisions are based on enacted or substantively enacted laws. Changes in those laws could affect amounts recognized in net 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.

The Company utilizes commodity risk management contracts to manage its commodity price risk on its petroleum and natural gas sales. The Company may also utilize foreign exchange risk management contracts to reduce its exposure to foreign exchange risk associated with its interest payments on its US dollar denominated term debt. The calculated fair value of the risk management contracts relies on external observable market data including quoted forward commodity prices and foreign exchange rates. The resulting fair value estimates may not be indicative of the amounts actually realized at settlement and as such are subject to measurement uncertainty.

The measurement of stock-based compensation includes volatility, expected life, risk-free rates and forfeiture rates which are based on management's assumptions and estimates.

The measurement of the warrant liability includes volatility, expected life and risk-free rates which are based on management's assumptions and estimates.

The measurement of the current portion of term debt includes assumptions of expected excess cashflows which are based on management's estimates and relies on external observable market data including quoted forward commodity prices.

The economic recovery from the COVID-19 pandemic coupled with global supply uncertainty as a result of the Russian invasion of Ukraine and significant underinvestment that has occurred in the energy industry over the past several years, drove crude oil and natural gas prices to multi-year highs in the first half of 2022. This in turn had a significant impact on the Company’s commodity sales from production. Global oil prices declined in the latter half of 2022, due to recessionary fears caused by central banks raising interest rates and uncertainty on global demand growth forecasts. Athabasca uses forward commodity price curves as an input in assessing the value of its crude oil and natural gas assets and these inputs could be affected by the unknown future impact of the factors above. At December 31, 2022, Management has incorporated the anticipated impacts of the factors above in its estimates and judgments in preparation of the 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).

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”, "Capital Expenditures Net of Capital-Carry", "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 December 31, 2022	Three months ended December 31, 2021	Year ended December 31, 2022	Year ended December 31, 2021
Cash flow from operating activities	$ 69,368	$ 81,189	$ 315,618	$ 194,253
Changes in non-cash working capital	(23,356)	(38,794)	(8,970)	(11,872)
Settlement of provisions	62	248	1,356	1,684
ADJUSTED FUNDS FLOW	46,074	42,643	308,004	184,065
Capital expenditures	(13,029)	(18,352)	(147,449)	(92,142)
FREE CASH FLOW	$ 33,045	$ 24,291	$ 160,555	$ 91,923

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 13 reconciles Light Oil Operating Income to its segmented income in *Note 17 - Segmented Information* of the Consolidated Financial Statements for the three months and year ended December 31, 2022. The table on page 10 reconciles Thermal Oil Operating Income to its segmented income in *Note 17 - Segmented Information* of the Consolidated Financial Statements for the three months and year ended December 31, 2022.

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 17 - Segmented Information* of the Consolidated Financial Statements for the three months and year ended December 31, 2022.

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.

Capital Expenditures Net of Capital-Carry

The non-GAAP financial measure Capital Expenditures Net of Capital-Carry in this MD&A is calculated as capital expenditures less the Greater Kaybob capital-carry. This measure allows management and others to evaluate the true net cash outflow related to Athabasca's capital expenditures.

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 December 31, 2022	2021	Year ended December 31, 2022	2021
Greater Placid:					
Condensate NGLs	bbl/d	843	1,211	962	1,375
Other NGLs	bbl/d	360	494	411	512
Natural gas(1)	mcf/d	10,259	13,181	11,149	14,537
Total Greater Placid	boe/d	2,913	3,902	3,232	4,310
Greater Kaybob:					
Oil(2)	bbl/d	1,707	1,885	1,886	2,164
Other NGLs	bbl/d	266	342	319	344
Natural gas(1)	mcf/d	4,526	5,603	5,020	5,969
Total Greater Kaybob	boe/d	2,727	3,161	3,041	3,503
Light Oil:					
Oil(2)	bbl/d	1,707	1,885	1,886	2,164
Condensate NGLs	bbl/d	843	1,211	962	1,375
Oil and condensate NGLs	bbl/d	2,550	3,096	2,848	3,539
Other NGLs	bbl/d	626	836	730	856
Natural gas(1)	mcf/d	14,785	18,784	16,169	20,506
Total Light Oil division	boe/d	5,640	7,063	6,273	7,813
Total Thermal Oil division bitumen	bbl/d	30,210	28,084	28,989	26,805
Total Company production	boe/d	35,850	35,147	35,262	34,618

(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 December 31, 2022	2021	Year ended December 31, 2022	2021
Greater Placid:					
Condensate NGLs	bbl/d	843	1,211	962	1,375
Other NGLs	bbl/d	360	494	411	512
Total Greater Placid Liquids	bbl/d	1,203	1,705	1,373	1,887
as % of Greater Placid production		41%	44%	42%	44%
Greater Kaybob:					
Oil	bbl/d	1,707	1,885	1,886	2,164
Other NGLs	bbl/d	266	342	319	344
Total Greater Kaybob Liquids	bbl/d	1,973	2,227	2,205	2,508
as % of Greater Kaybob production		72%	70%	73%	72%
Total Light Oil:					
Oil and condensate NGLs	bbl/d	2,550	3,096	2,848	3,539
Other NGLs	bbl/d	626	836	730	856
Total Light Oil division Liquids	bbl/d	3,176	3,932	3,578	4,395
as % of Light Oil production		56%	56%	57%	56%
Total Company:					
Total Light Oil division Liquids	bbl/d	3,176	3,932	3,578	4,395
Total Thermal Oil division bitumen	bbl/d	30,210	28,084	28,989	26,805
Total Company Liquids	bbl/d	33,386	32,016	32,567	31,200
as % of Company production		93%	91%	92%	90%

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 84% of that production will be comprised of bitumen, 7% shale gas, 4% tight oil, 3% 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").

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, 2022, 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, 2022, 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, 2022.

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;
- 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; and
- negative economic impacts as a result of the spread of COVID-19 (coronavirus).

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; expectation of results of CRA audits and reassessments; on stream timing of five additional well pairs at Leismer; the Company's anticipated sources of funding for 2023 and beyond; the Company’s use of Free 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
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