Management's Discussion and Analysis

December 31, 2021

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 2, 2022 and should be read in conjunction with the audited consolidated financial statements of the Company for the years ended December 31, 2021 and 2020 ("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 2, 2022 ("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: Flexible Capital, Strong Liquidity, Prudent Risk Management

Athabasca remains focused on maximizing corporate free cash flow and maintaining its production base. The Company has long term 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, 2021

Corporate

- Fourth quarter production of 35,147 boe/d (91% Liquids[(1)]) and 2021 production of 34,618 boe/d (90% Liquids[(1)]).
- Petroleum, natural gas & midstream sales of $292.4 million in the fourth quarter and $1.0 billion for 2021.
- Operating Income[(1)] of $110.6 million ($65.7 million Operating Income Net of Realized Hedging[(1)]) in the fourth quarter and $390.4 million for 2021 ($278.7 million Operating Income Net of Realized Hedging[(1)])
- Fourth quarter Adjusted Funds Flow[(1)] of $42.6 million (cash flow from operating activities $81.2 million) and $184.1 million for 2021 (cash flow from operating activities $194.3 million).
- Fourth quarter Free Cash Flow[(1)] of $24.3 million and $91.9 million for 2021.
- Liquidity[(1)] of $300.9 million, including $223.1 million of cash as at December 31, 2021.
- The Company completed the refinancing of its 2022 Second Lien Notes through the issuance of US$350 million of New Second Lien Notes maturing in 2026, a new $110 million syndicated reserve based credit facility and an increased $50 million unsecured letter of credit facility.

Thermal Oil Division

- Fourth quarter production of 28,084 bbl/d and 2021 production of 26,805 bbl/d.
- Petroleum, natural gas & midstream sales of $265.1 million in the fourth quarter and $914.1 million for 2021.
- Operating Income[(1)] of $82.7 million for the fourth quarter and $287.3 million for 2021.
- Operating Netbacks[(1)] of $33.43/bbl in the fourth quarter and $29.49/bbl for 2021.
- Capital expenditures of $82.0 million for 2021 were focused on sustaining projects at Leismer. Activity included three infill wells and completing the Pad 8 and associated infrastructure. Pad 8 commenced steaming in October with first production in January 2022.

Light Oil Division

- Fourth quarter production of 7,063 boe/d (56% Liquids[(1)]) and 2021 production of 7,813 boe/d (56% Liquids[(1)]).
- Petroleum, natural gas & midstream sales of $40.2 million in the fourth quarter and $147.7 million for 2021.
- Operating Income[(1)] of $27.9 million for the fourth quarter and $103.1 million for 2021.
- Strong Operating Netback[(1)] of $42.95/boe for the fourth quarter and $36.15/boe for 2021.
- Field activity focused on maintaining low operating cost structure with no drilling activity in 2021.

(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, 2021	2020	Year ended December 31, 2021	2020
CONSOLIDATED				
Petroleum and natural gas production (boe/d)[1]	35,147	34,233	34,618	32,483
Petroleum, natural gas and midstream sales	$ 292,405	$ 155,109	$ 1,016,323	$ 464,648
Operating Income (Loss)[1]	$ 110,648	$ 40,288	$ 390,353	$ 51,862
Operating Income (Loss) Net of Realized Hedging[1][2]	$ 65,735	$ 30,935	$ 278,664	$ 81,011
Operating Netback ($/boe)[1]	$ 35.43	$ 12.88	$ 31.00	$ 4.31
Operating Netback Net of Realized Hedging ($/boe)[1][2]	$ 21.05	$ 9.89	$ 22.13	$ 6.73
Capital expenditures	$ 18,352	$ 17,202	$ 92,142	$ 111,640
Capital Expenditures Net of Capital-Carry[1]	$ 18,352	$ 17,202	$ 92,142	$ 88,900
Free Cash Flow[1]	$ 24,291	$ (6,449)	$ 91,923	$ (107,627)
THERMAL OIL DIVISION				
Bitumen production (bbl/d)	28,084	24,839	26,805	22,745
Petroleum, natural gas and midstream sales	$ 265,076	$ 132,635	$ 914,058	$ 383,940
Operating Income (Loss)[1]	$ 82,729	$ 20,746	$ 287,261	$ (10,140)
Operating Netback ($/bbl)[1]	$ 33.43	$ 9.17	$ 29.49	$ (1.19)
Capital expenditures	$ 12,355	$ 16,915	$ 81,985	$ 49,787
LIGHT OIL DIVISION				
Petroleum and natural gas production (boe/d)[1]	7,063	9,394	7,813	9,738
Percentage Liquids (%)[1]	56%	58%	56%	60%
Petroleum, natural gas and midstream sales	$ 40,237	$ 30,180	$ 147,705	$ 107,600
Operating Income (Loss)[1]	$ 27,919	$ 19,542	$ 103,092	$ 62,002
Operating Netback ($/boe)[1]	$ 42.95	$ 22.61	$ 36.15	$ 17.40
Capital expenditures	$ 5,291	$ 117	$ 6,931	$ 61,651
Capital Expenditures Net of Capital-Carry[1]	$ 5,291	$ 117	$ 6,931	$ 38,911
CASH FLOW AND FUNDS FLOW				
Cash flow from operating activities	$ 81,189	$ 16,079	$ 194,253	$ (22,910)
per share - basic	$ 0.15	$ 0.03	$ 0.37	$ (0.04)
Adjusted Funds Flow[1]	$ 42,643	$ 10,753	$ 184,065	$ (18,727)
per share - basic	$ 0.08	$ 0.02	$ 0.35	$ (0.04)
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)				
Net income (loss) and comprehensive income (loss)	$ 384,073	$ (56,891)	$ 457,608	$ (657,525)
per share - basic	$ 0.72	$ (0.11)	$ 0.86	$ (1.24)
per share - diluted	$ 0.70	$ (0.11)	$ 0.84	$ (1.24)
COMMON SHARES OUTSTANDING				
Weighted average shares outstanding - basic	530,744,156	530,675,391	530,692,724	528,837,646
Weighted average shares outstanding - diluted	551,124,848	533,453,490	546,717,181	528,837,646

As at ($ Thousands)	December 31, 2021	December 31, 2020
LIQUIDITY AND BALANCE SHEET		
Cash and cash equivalents	$ 223,056	$ 165,201
Restricted cash	$ —	$ 135,624
Available credit facilities[3]	$ 77,844	$ 348
Face value of term debt[4]	$ 443,730	$ 572,940

(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 $44.9 million and $111.7 million for the three months and year ended December 31, 2021 (three months and year ended December 31, 2020 - $9.4 million loss and $29.1 million gain).
(3) Includes available credit under Athabasca's Credit Facility and Unsecured Letter of Credit Facility (see page 14).
(4) The face value of the term debt at December 31, 2021 was US$350 million (December 31, 2020 – US$450 million) translated into Canadian dollars at the December 31, 2021 exchange rate of US$1.00 =C$1.2678 (December 31, 2020 – C$1.2732).

INDEPENDENT RESERVES EVALUATION

The Company's qualified independent reserve evaluators, McDaniel & Associates Consultants Ltd. ("McDaniel"), completed independent reserve evaluations effective December 31, 2021 and 2020. 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 2, 2022, for further details relating to Athabasca's reserves.

Reserves

At December 31, 2021, the Company had 1,301 MMboe of Proved plus Probable Reserves (December 31, 2020 - 1,156 MMboe). The following table shows the Company's reserves by division (tables may not add due to rounding):

	December 31, 2021			December 31, 2020		
Reserves	Proved Developed Producing	Proved	Proved plus Probable	Proved Developed Producing	Proved	Proved plus Probable
Thermal Oil Division(1)						
Leismer (MMbbl)	41	335	705	29	333	694
Corner (MMbbl)	—	—	353	—	—	353
Hangingstone (MMbbl)	33	79	172	32	32	36
Total Thermal Oil Division (MMbbl)	74	414	1,230	61	365	1,083
Light Oil Division(2)						
Greater Placid (MMboe)	7	20	47	8	30	49
Greater Kaybob (MMboe)	6	7	24	7	8	25
Total Light Oil Division (MMboe)	13	27	72	14	37	73
Consolidated reserves (MMboe)	87	441	1,301	76	403	1,156

(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 increased by 21% to 74 MMbbl due to Leismer's new wells. 2P reserves increased 14% from 1,083 MMbbl to 1,230 MMbbl for the year ended December 31, 2021. The increase was primarily due to the undeveloped reserves at Hangingstone becoming economic in the year when run on the year-end third party reserve price forecasts.

In the Light Oil Division, the Proved plus Probable ("2P") reserves and 2P Liquids weighting were relatively consistent year-over-year with 72 MMboe 2P reserves and a 57% 2P Liquids weighting (December 31, 2020 - 56%).

BUSINESS ENVIRONMENT

Benchmark prices

(Average)	Three months ended December 31, 2021	2020	Change	Year ended December 31, 2021	2020	Change
Crude oil:						
West Texas Intermediate (WTI) (US$/bbl)[1]	$ 77.19	$ 42.66	81 %	$ 67.91	$ 39.40	72 %
West Texas Intermediate (WTI) (C$/bbl)[1]	$ 97.25	$ 55.58	75 %	$ 85.11	$ 52.81	61 %
Western Canadian Select (WCS) (C$/bbl)[2]	$ 78.67	$ 43.40	81 %	$ 68.70	$ 35.58	93 %
Edmonton Par (C$/bbl)[3]	$ 93.14	$ 49.98	86 %	$ 80.09	$ 45.17	77 %
Edmonton Condensate (C5+) (C$/bbl)[4]	$ 99.24	$ 55.05	80 %	$ 84.99	$ 48.79	74 %
WCS Differential:						
to WTI (US$/bbl)	$ (14.64)	$ (9.30)	57 %	$ (13.04)	$ (12.60)	3 %
to WTI (C$/bbl)	$ (18.58)	$ (12.18)	53 %	$ (16.41)	$ (17.23)	(5) %
Edmonton Par Differential:						
to WTI (US$/bbl)	$ (3.10)	$ (4.07)	(24) %	$ (3.88)	$ (5.33)	(27) %
to WTI (C$/bbl)	$ (4.11)	$ (5.60)	(27) %	$ (5.02)	$ (7.64)	(34) %
Natural gas:						
AECO (C$/GJ)[5][6]	$ 4.41	$ 2.50	76 %	$ 3.43	$ 2.11	63 %
Chicago Citygate (US$/MMBtu)[6]	$ 4.57	$ 2.27	101 %	$ 4.48	$ 1.86	141 %
Foreign exchange:						
USD : CAD	1.2599	1.3029	(3) %	1.2533	1.3403	(6) %

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

OUTLOOK

2022 Operational & Financial Guidance ($ millions, unless otherwise noted)	Original Guidance[3] Dec. 1, 2021	Updated Guidance[4] Feb. 2, 2022
Production (boe/d)[1]	33,000-34,000	33,000-34,000
% Liquids[1]	~92%	~92%
Adjusted EBITDA[1][2]	$ 300	$ 350
Adjusted Funds Flow[1]	$ 250	$ 300
Free Cash Flow[1]	$ 125	$ 180
Capital Expenditures	$ 128	$ 128
Thermal Oil	$ 115	$ 115
Light Oil	$ 13	$ 13

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP 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 and non-cash stock-based compensation.
(3) US$70 WTI, US$13.50 WCS differentials, 0.80 US$/C$ FX.
(4) US$85 WTI, US$13.50 WCS differentials, 0.80 US$/C$ FX.

Athabasca is maintaining its previously announced 2022 guidance as released February 2, 2022 including a $128 million capital program in 2022 and corporate production between 33-34,000 boe/d. The largest capital allocation of $115 million will be to Thermal Oil, including a turnaround at Leismer, the drilling of two infill wells and another five well pairs at Leismer following a successful 2021 drilling program. Light Oil capital allocation is $13 million and includes the completion of three Duvernay wells in the first quarter of 2022.

The Company is planning to utilize 100% of near-term free cash flow to reduce its term debt and is anticipating being in a net cash position by year end 2022 at current commodity prices. Athabasca expects to also achieve its target term debt of US$175 million (50% reduction) in the first half of 2023. The Company recently redeemed US$25 million of debt in the open market with scheduled future debt repayments in May and November.

2021 Guidance Review

Production exceeded original guidance with strong facility utilization in Thermal Oil and minimal field downtime in Light Oil. Athabasca initiated guidance in mid-2021 for Adjusted EBITDA, Adjusted Funds Flow, Free Cash Flow and Unrestricted cash balances, and increased its guidance throughout the year as higher commodity prices were realized.

2021 Guidance	Original Guidance	Updated Guidance				Actual
($ millions, unless otherwise noted)	Dec. 2, 2020	Mar. 3, 2021	May 4, 2021	Jul. 28, 2021	Nov. 3, 2021	Full year
Production (boe/d)[1]	31,000-33,000	31,000-33,000	32,000-34,000	32,000-34,000	34,250	34,618
Adjusted EBITDA[1][2]	$ —	$ —	$ 210	$ 235	$ 255	$ 244
Adjusted Funds Flow[1]	$ —	$ —	$ 155	$ 175	$ 190	$ 184
Capital Expenditures	$ 75	$ 100	$ 100	$ 100	$ 100	$ 92
Free Cash Flow[1]	$ —	$ —	$ 55	$ 75	$ 90	$ 92

(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 and non-cash stock-based compensation.

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, 2021	2020	Year ended December 31, 2021	2020
PRODUCTION				
Bitumen (bbl/d)	28,084	24,839	26,805	22,745
Oil and condensate (bbl/d)(1)	3,096	4,686	3,539	5,081
Natural gas (Mcf/d)(1)	18,784	23,529	20,506	23,229
Other natural gas liquids (bbl/d)(1)	836	787	856	785
Total (boe/d)(1)	35,147	34,233	34,618	32,483

(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, 2021	2020	Year ended December 31, 2021	2020
Petroleum, natural gas and midstream sales(1)	$ 305,313	$ 162,815	$ 1,061,763	$ 491,540
Royalties	(17,972)	(1,843)	(37,717)	(6,090)
Cost of diluent(1)	(105,753)	(57,806)	(360,824)	(212,400)
Operating expenses	(48,562)	(39,184)	(180,831)	(137,357)
Transportation and marketing(2)	(22,378)	(23,694)	(92,038)	(83,831)
Operating Income (Loss)(3)	110,648	40,288	390,353	51,862
Realized gain (loss) on commodity risk management contracts	(44,913)	(9,353)	(111,689)	29,149
OPERATING INCOME (LOSS) NET OF REALIZED HEDGING(3)	$ 65,735	$ 30,935	$ 278,664	$ 81,011
REALIZED PRICES(3)				
Heavy oil (Blended bitumen) ($/bbl)(3)	$ 75.65	$ 41.51	$ 66.30	$ 32.15
Oil and condensate ($/bbl)(3)	93.33	50.89	79.10	43.82
Natural gas ($/Mcf)(3)	5.29	2.82	4.03	2.34
Other natural gas liquids ($/bbl)(3)	58.60	29.43	49.29	21.60
Realized price (net of cost of diluent) ($/boe)(3)	63.89	33.56	55.67	23.19
Royalties ($/boe)(3)	(5.75)	(0.59)	(3.00)	(0.51)
Operating expenses ($/boe)(3)	(15.55)	(12.52)	(14.36)	(11.41)
Transportation and marketing ($/boe)(3)	(7.16)	(7.57)	(7.31)	(6.96)
Operating Netback ($/boe)(3)	35.43	12.88	31.00	4.31
Realized gain (loss) on commodity risk mgmt. contracts ($/boe)(3)	(14.38)	(2.99)	(8.87)	2.42
OPERATING NETBACK NET OF REALIZED HEDGING ($/boe)(3)	$ 21.05	$ 9.89	$ 22.13	$ 6.73

(1) Non-GAAP measure includes intercompany NGLs (i.e. condensate) sold by the Light Oil segment to the Thermal Oil segment for use as diluent that is eliminated on consolidation.
(2) Transportation and marketing excludes non-cash costs of $0.6 million and $1.5 million for the three months and year ended December 31, 2021.
(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, 2021	2020	Year ended December 31, 2021	2020
Operating Income (Loss) Net of Realized Hedging(1)	$ 65,735	$ 30,935	$ 278,664	$ 81,011
Non-cash transportation and marketing	(558)	—	(1,487)	—
Unrealized gain (loss) on commodity risk management contracts	28,515	4,886	(34,083)	13,329
Impairment reversal (expense)	345,700	—	345,700	(471,839)
Depletion and depreciation	(24,296)	(25,495)	(95,673)	(110,078)
Gain (loss) on sale of assets	23	58	20,123	21,289
Exploration and non-producing asset expenses	(430)	(514)	(2,824)	(22,410)
CONSOLIDATED SEGMENTS INCOME (LOSS)	$ 414,689	$ 9,870	$ 510,420	$ (488,698)

(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, 2021	2020	Year ended December 31, 2021	2020
Thermal Oil Division	$ 12,355	$ 16,915	$ 81,985	$ 49,787
Light Oil Division	5,291	117	6,931	61,651
Corporate assets	706	170	3,226	202
Total capital expenditures(1)(2)(3)	18,352	17,202	92,142	111,640
Less: Greater Kaybob capital-carry	—	—	—	(22,740)
TOTAL CAPITAL EXPENDITURES NET OF CAPITAL-CARRY(4)	$ 18,352	$ 17,202	$ 92,142	$ 88,900

(1) For the three months and year ended December 31, 2021, expenditures include capitalized cash based stock-based compensation costs of $0.7 million and $3.2 million (three months and year ended December 31, 2020 - $0.2 million).
(2) For the three months and year ended December 31, 2021, expenditures include capitalized staff costs of $1.5 million and $6.3 million (three months and year ended December 31, 2020 - $1.2 million and $5.6 million).
(3) Excludes non-cash capitalized stock-based compensation and non-cash capitalized decommissioning obligation asset costs.
(4) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

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 50 years and a reserve life index of approximately 100 years (proved plus probable). The Leismer Project has Proved plus Probable Reserves of approximately 705 MMbbl[1] and Best Estimate Development Pending Contingent Resources of 314 MMbbl (risked)[1] (348 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 50 years (proved plus probable). Hangingstone has Proved plus Probable Reserves of approximately 172 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. 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% (US$75 implied WTI assuming a US$15 WCS differential). 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. Prior to 2021, no amounts were paid in respect of the Royalty to Burgess Energy Holdings, L.L.C. (“Burgess”). In the fourth quarter of 2021, as a result of the improved commodity prices, Athabasca paid $5.2 million in respect of the Royalty to Burgess.

(1) Based on the report of Athabasca's independent reserve evaluator effective December 31, 2021. Refer to the "Advisories and Other Guidance" section within this MD&A and the AIF for additional information about the Company's reserves and resources.

Leismer Operating Results

	Three months ended December 31, 2021	2020	Year ended December 31, 2021	2020
VOLUMES				
Bitumen production (bbl/d)	18,794	17,379	17,707	18,264
Bitumen sales (bbl/d)	18,348	17,241	17,623	18,320
Heavy oil (blended bitumen) sales (bbl/d)	25,840	24,033	24,670	25,519

($ Thousands, unless otherwise noted)	Three months ended December 31, 2021	2020	Year ended December 31, 2021	2020
Heavy oil (blended bitumen) sales	$ 179,195	$ 92,192	$ 597,343	$ 300,923
Cost of diluent	(70,902)	(38,939)	(231,383)	(155,797)
Total bitumen sales	108,293	53,253	365,960	145,126
Royalties	(9,699)	(429)	(18,834)	(1,835)
Operating expenses - non-energy	(13,107)	(11,695)	(47,635)	(46,227)
Operating expenses - energy	(14,647)	(8,489)	(49,621)	(31,322)
Transportation and marketing	(11,807)	(11,706)	(47,778)	(45,545)
LEISMER OPERATING INCOME (LOSS)[1]	$ 59,033	$ 20,934	$ 202,092	$ 20,197
REALIZED PRICE[1]				
Heavy oil (blended bitumen) sales ($/bbl)[1]	$ 75.38	$ 41.70	$ 66.34	$ 32.22
Bitumen sales ($/bbl)[1]	$ 64.15	$ 33.57	$ 56.89	$ 21.64
Royalties ($/bbl)[1]	(5.75)	(0.27)	(2.93)	(0.27)
Operating expenses - non-energy ($/bbl)[1]	(7.76)	(7.37)	(7.41)	(6.89)
Operating expenses - energy ($/bbl)[1]	(8.68)	(5.35)	(7.71)	(4.67)
Transportation and marketing ($/bbl)[1]	(6.99)	(7.38)	(7.43)	(6.79)
LEISMER OPERATING NETBACK ($/bbl)[1]	$ 34.97	$ 13.20	$ 31.41	$ 3.02

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

As a result of the infill wells being placed on production late in the second quarter of 2021, Leismer's bitumen production increased to 18,794 bbl/d for the fourth quarter of 2021 as compared to the same period of 2020, and decreased to 17,707 bbl/d for 2021 as compared to 2020.

The Leismer Operating Netbacks are higher in 2021 primarily due to higher WCS benchmark oil prices, partially offset by higher energy operating costs and royalties.

Total royalties increased in the fourth quarter of 2021 due to higher oil prices.

Total operating expenses were $16.44/bbl in the fourth quarter of 2021 and $15.12/bbl in 2021, compared to $12.72/bbl and $11.56/bbl respectively in the comparable periods of 2020. Energy operating costs per barrel increased in 2021 relative to the prior year periods due to higher natural gas and electricity prices in 2021.

Hangingstone Operating Results

	Three months ended December 31, 2021	2020	Year ended December 31, 2021	2020
VOLUMES				
Bitumen production (bbl/d)	9,290	7,460	9,098	4,481
Bitumen sales (bbl/d)	8,541	7,372	9,057	4,837
Heavy oil (blended bitumen) sales (bbl/d)	12,245	10,698	13,099	7,113

($ Thousands, unless otherwise noted)	Three months ended December 31, 2021	2020	Year ended December 31, 2021	2020
Heavy oil (blended bitumen) and midstream sales	$ 85,881	$ 40,443	$ 316,715	$ 83,017
Cost of diluent	(34,851)	(18,867)	(129,441)	(56,603)
Total bitumen and midstream sales	51,030	21,576	187,274	26,414
Royalties	(4,390)	(128)	(8,723)	(315)
Operating expenses - non-energy	(5,249)	(5,226)	(20,882)	(16,102)
Operating expenses - energy	(9,642)	(6,918)	(38,298)	(15,823)
Transportation and marketing[1]	(8,053)	(9,492)	(34,202)	(24,511)
HANGINGSTONE OPERATING INCOME (LOSS)[2]	$ 23,696	$ (188)	$ 85,169	$ (30,337)
REALIZED PRICE[2]				
Heavy oil (blended bitumen) and midstream sales ($/bbl)[2]	$ 76.23	$ 41.09	$ 66.24	$ 31.89
Bitumen and midstream sales ($/bbl)[2]	$ 64.94	$ 31.81	$ 56.65	$ 14.92
Royalties ($/bbl)[2]	(5.59)	(0.19)	(2.64)	(0.18)
Operating expenses - non-energy ($/bbl)[2]	(6.68)	(7.71)	(6.32)	(9.10)
Operating expenses - energy ($/bbl)[2]	(12.27)	(10.20)	(11.59)	(8.94)
Transportation and marketing ($/bbl)[2]	(10.25)	(14.00)	(10.35)	(13.85)
HANGINGSTONE OPERATING NETBACK ($/bbl)[2]	$ 30.15	$ (0.29)	$ 25.75	$ (17.15)

(1) Transportation and marketing excludes non-cash costs of $0.6 million and $1.5 million for the three months and year ended December 31, 2021.
(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures and production disclosure.

Hangingstone bitumen production in 2021 was higher than 2020 due to voluntary curtailments and a five-month shut-in period in response to low oil prices during 2020. The facility was restarted September 1, 2020 and production ramped up to pre-suspension levels by the end of the first quarter of 2021.

The Hangingstone Operating Netbacks are higher in 2021 primarily due to higher WCS benchmark oil prices and lower transportation and non-energy operating costs, partially offset by higher energy operating costs and royalties.

Total royalties increased in the fourth quarter of 2021 due to higher oil prices.

Total operating expenses were $18.95/bbl in the fourth quarter of 2021 and $17.91/bbl in 2021, compared to $17.91/bbl and $18.04/bbl respectively in the comparable periods of 2020. Non-energy costs per barrel decreased relative to the prior year periods due to cost optimization initiatives including lower personnel costs. Energy operating costs per barrel increased relative to the prior year periods primarily due to higher natural gas and electricity prices in 2021.

Consolidated Thermal Oil Operating Results

	Three months ended December 31, 2021	2020	Year ended December 31, 2021	2020
VOLUMES				
Bitumen production (bbl/d)	28,084	24,839	26,805	22,745
Bitumen sales (bbl/d)	26,889	24,613	26,680	23,157
Heavy oil (blended bitumen) sales (bbl/d)	38,085	34,731	37,769	32,632

($ Thousands, unless otherwise noted)	Three months ended December 31, 2021	2020	Year ended December 31, 2021	2020
Heavy oil (blended bitumen) and midstream sales	$ 265,076	$ 132,635	$ 914,058	$ 383,940
Cost of diluent	(105,753)	(57,806)	(360,824)	(212,400)
Total bitumen and midstream sales	159,323	74,829	553,234	171,540
Royalties	(14,089)	(557)	(27,557)	(2,150)
Operating expenses - non-energy	(18,356)	(16,921)	(68,517)	(62,329)
Operating expenses - energy	(24,289)	(15,407)	(87,919)	(47,145)
Transportation and marketing(1)	(19,860)	(21,198)	(81,980)	(70,056)
THERMAL OIL OPERATING INCOME (LOSS)(2)	$ 82,729	$ 20,746	$ 287,261	$ (10,140)
REALIZED PRICE(2)				
Heavy oil (blended bitumen) and midstream sales ($/bbl)(2)	$ 75.65	$ 41.51	$ 66.30	$ 32.15
Bitumen and midstream sales ($/bbl)(2)	$ 64.40	$ 33.05	$ 56.81	$ 20.24
Royalties ($/bbl)(2)	(5.70)	(0.25)	(2.83)	(0.25)
Operating expenses - non-energy ($/bbl)(2)	(7.42)	(7.47)	(7.04)	(7.35)
Operating expenses - energy ($/bbl)(2)	(9.82)	(6.80)	(9.03)	(5.56)
Transportation and marketing ($/bbl)(2)	(8.03)	(9.36)	(8.42)	(8.27)
THERMAL OIL OPERATING NETBACK ($/BBL)(2)	$ 33.43	$ 9.17	$ 29.49	$ (1.19)

(1) Transportation and marketing excludes non-cash costs of $0.6 million and $1.5 million the three months and year ended December 31, 2021.
(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, 2021	2020	Year ended December 31, 2021	2020
Thermal Oil Operating Income (Loss)(1)	$ 82,729	$ 20,746	$ 287,261	$ (10,140)
Non-cash transportation and marketing	(558)	—	(1,487)	—
Impairment reversal (expense)	272,800	—	272,800	(207,884)
Depletion and depreciation	(13,438)	(11,117)	(48,309)	(46,912)
Gain (loss) on sale of assets	23	58	20,023	21,289
Exploration and non-producing asset expenses	(430)	(514)	(2,824)	(22,410)
THERMAL OIL SEGMENT INCOME (LOSS)	$ 341,126	$ 9,173	$ 527,464	$ (266,057)

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

In the first quarter of 2020 Athabasca recognized an impairment loss of $207.9 million as it fully impaired the Hangingstone Cash Generating Unit (“CGU”) due to the suspension of operations, market volatility and low commodity price forecasts. 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. Compared to the same periods of 2020, depletion increased in 2021 primarily due to the higher Thermal Oil production associated with the restart of Hangingstone. Non-producing asset expenses in 2020 related to Hangingstone costs incurred during its suspension were mainly comprised of committed transportation and utilities distribution costs, and excluded costs directly associated with suspending the asset which were recognized in restructuring expenses.

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. In 2020, Athabasca recorded a gain of $21.0 million on a royalty transaction with Burgess related to cash proceeds received in relation to the Company's fully impaired assets, including Hangingstone, Birch, Dover West and Grosmont. The remaining 2020 cash proceeds of $49 million were allocated to Leismer and Corner, and reduced the carrying value of those assets.

Thermal Oil Capital Expenditures

($ Thousands)	Three months ended December 31, 2021	Three months ended December 31, 2020	Year ended December 31, 2021	Year ended December 31, 2020
Leismer Project	$ 10,357	$ 14,754	$ 74,689	$ 41,897
Hangingstone Project	1,925	2,108	7,024	7,572
Other Thermal Oil exploration	73	53	272	318
TOTAL THERMAL OIL CAPITAL EXPENDITURES(1)	$ 12,355	$ 16,915	$ 81,985	$ 49,787

(1) For the three months and year ended December 31, 2021, capital expenditures include $1.0 million and $4.1 million of capitalized staff costs (three months and year ended December 31, 2020 - $0.7 million and $3.1 million).

Thermal Oil capital expenditures for 2021 of $82.0 million were primarily related to sustaining operations at Leismer along with routine pump replacements across both assets. In 2021 the Company drilled a new well pair at Pad 7, two infill wells at Pad 6 and completed the drilling of five well pairs at Pad 8 along with pipeline and surface facilities. Pad 8 commenced steaming in October with first production in January 2022.

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, 2021, the Light Oil Division had approximately 72 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 85,000 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. 75% of Athabasca's Greater Kaybob development capital from mid-2016 to early-2020 was funded by its joint venture partner under a multi-year $219 million (undiscounted) capital-carry commitment which was designed to support approximately $1 billion of gross Duvernay investment to delineate the large land base which is now complete. The $219 million capital carry commitment was completed during the first quarter of 2020.

(1) Based on the report of Athabasca's independent reserve evaluator effective December 31, 2021. 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, 2021	2020	Year ended December 31, 2021	2020
PRODUCTION[1]				
Oil and condensate (bbl/d)	3,096	4,686	3,539	5,081
Natural gas (Mcf/d)	18,784	23,529	20,506	23,229
Other natural gas liquids (bbl/d)	836	787	856	785
Total (boe/d)	7,063	9,394	7,813	9,738
Consisting of:				
Greater Placid area (boe/d)	3,902	5,347	4,310	5,138
% Liquids	44%	44%	44%	47%
Greater Kaybob area (boe/d)	3,161	4,047	3,503	4,600
% Liquids	70%	77%	72%	75%

(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, 2021	2020	Year ended December 31, 2021	2020
Petroleum and natural gas sales	$ 40,237	$ 30,180	$ 147,705	$ 107,600
Royalties	(3,883)	(1,286)	(10,160)	(3,940)
Operating expenses	(5,917)	(6,856)	(24,395)	(27,883)
Transportation and marketing	(2,518)	(2,496)	(10,058)	(13,775)
LIGHT OIL OPERATING INCOME (LOSS)[1]	$ 27,919	$ 19,542	$ 103,092	$ 62,002
REALIZED PRICES[1]				
Oil and condensate ($/bbl)[1]	$ 93.33	$ 50.89	$ 79.10	$ 43.82
Natural gas ($/Mcf)[1]	5.29	2.82	4.03	2.34
Other natural gas liquids ($/bbl)[1]	58.60	29.43	49.29	21.60
Realized price ($/boe)[1]	61.92	34.92	51.79	30.19
Royalties ($/boe)[1]	(5.98)	(1.49)	(3.56)	(1.11)
Operating expenses ($/boe)[1]	(9.11)	(7.93)	(8.55)	(7.82)
Transportation and marketing ($/boe)[1]	(3.88)	(2.89)	(3.53)	(3.86)
LIGHT OIL OPERATING NETBACK ($/boe)[1]	$ 42.95	$ 22.61	$ 36.15	$ 17.40

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

The lower Light Oil production in 2021 is due to natural declines as no new wells have been placed on-stream since the first half of 2020.

Athabasca generated Light Oil Operating Income of $27.9 million ($42.95/boe Operating Netback) in the fourth quarter and $103.1 million ($36.15/boe Operating Netback) in 2021. The Operating Income and Operating Netbacks were higher than in 2020 primarily due to stronger commodity pricing.

Royalties increased in 2021 compared to 2020 due to stronger commodity prices and wells coming off royalty programs.

Light Oil Segment Income (Loss)

($ Thousands)	Three months ended December 31, 2021	2020	Year ended December 31, 2021	2020
Light Oil Operating Income (Loss)[1]	$ 27,919	$ 19,542	$ 103,092	$ 62,002
Impairment reversal (expense)	72,900	—	72,900	(263,955)
Depletion and depreciation	(10,858)	(14,378)	(47,364)	(63,166)
Gain (loss) on sale of assets	—	—	100	—
LIGHT OIL SEGMENT INCOME (LOSS)	$ 89,961	$ 5,164	$ 128,728	$ (265,119)

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

In the first quarter of 2020 Athabasca recognized a Light Oil impairment of $264.0 million as a result of the market volatility and lower commodity price forecasts. As a result of the impairment and lower production, depletion and depreciation decreased in 2021.

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.

Light Oil Capital Expenditures

($ Thousands)	Three months ended December 31, 2021	2020	Year ended December 31, 2021	2020
Greater Placid	$ 854	$ (284)	$ 3,260	$ 22,029
Greater Kaybob	4,437	401	3,671	39,622
Total Light Oil capital expenditures[1]	5,291	117	6,931	61,651
Less: Greater Kaybob capital-carry	—	—	—	(22,740)
TOTAL LIGHT OIL CAPITAL EXPENDITURES NET OF CAPITAL-CARRY[2]	$ 5,291	$ 117	$ 6,931	$ 38,911

(1) For the three months and year ended December 31, 2021, capital expenditures include $0.5 million and $2.2 million of capitalized staff costs (three months and year ended December 31, 2020 - $0.5 million and $2.5 million).
(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

Minimal capital expenditures were incurred in 2021. In the fourth quarter, the Greater Kaybob capital expenditures were incurred in December for completion readiness and infrastructure work for three wells drilled in 2019 which were completed in the first quarter of 2022. The following table summarizes Athabasca's well activity for the three months and year ended December 31, 2021 and 2020:

	Three months ended December 31, 2021		2020		Year ended December 31, 2021		2020	
Well activity[1]	Gross	Net	Gross	Net	Gross	Net	Gross	Net
GREATER PLACID								
Wells drilled	—	—	—	—	—	—	—	—
Wells completed	—	—	—	—	—	—	7	4.9
Wells brought on production	—	—	—	—	—	—	10	7.0
GREATER KAYBOB								
Wells drilled	—	—	—	—	—	—	8	2.4
Wells completed	—	—	—	—	—	—	13	3.7
Wells brought on production	—	—	—	—	—	—	17	4.9

(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. The refinanced capital structure provides certainty to shareholders of the Company's ability to utilize Free Cash Flow to further reduce debt and enhance long-term resiliency. An active commodity risk management program and maintaining sufficient liquidity will allow the Company to manage periods of volatility. For 2022, it is anticipated that Athabasca's Light Oil and Thermal Oil capital and operating activities will be funded through cash flow from operating activities and existing cash and cash equivalents.

As at December 31, 2021, Athabasca had Liquidity of $300.9 million which included $223.1 million of cash and cash equivalents and $77.8 million of available capacity on its credit facilities.

Indebtedness

Athabasca had the following debt instruments and credit facilities in place as at December 31, 2021:

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 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.

Athabasca used the proceeds of the Offering, and cash on hand to redeem its US$450 million 2022 Notes. Athabasca redeemed the 2022 Notes at a redemption price of 100.0% of the principal amount of the 2022 Notes plus accrued and unpaid interest to, but excluding, the redemption date on November 6, 2021 (See Financial Statement Note 12).

Up until an aggregate amount of US$175 principal has been redeemed, the Company must direct at least 75% of free cashflow ("FCF") towards the redemption of the 2026 Notes at a price equal to 105% of the principal, plus accrued and unpaid interest. The redemption dates are semiannual with the October to March FCF redemption payable in May and the April to September FCF redemption payable in November. As a result, at December 31, 2021, $74.7 million of the term-debt is classified as current within the consolidated balance sheet. On February 2, 2022, Athabasca announced that it had completed the repayment of $32 million (US$25 million) of term debt. This payment was in advance of its first scheduled term debt repayment (May 2022) resulting in redemption and interest savings for the Company.

Credit Facility

On October 22, 2021, Athabasca entered into an amended and restated credit agreement with a syndicate of financial institutions. The amended and restated credit agreement provides for a $110 million reserves-based secured credit facility (the "Credit Facility") with a maturity date in October 2023. Existing outstanding letters of credit are no longer cash collateralized (See Financial Statement Note 12). As at December 31, 2021, the Company had no amounts drawn and $34.4 million of letters of credit issued and outstanding under the amended Credit Facility. As at December 31, 2020, Athabasca had no amounts drawn and $38.0 million letters of credit issued under the previous facility.

Cash-Collateralized Letter of Credit Facility

Athabasca previously maintained a $120.0 million cash-collateralized letter of credit facility (the "Letter of Credit Facility") with a Canadian bank for issuing letters of credit to counterparties. In conjunction with the Offering and the Credit Facility, the Letter of Credit Facility was cancelled (See Financial Statement Note 12). As at December 31, 2020, Athabasca had $96.0 million letters of credit issued under the Letter of Credit Facility.

Unsecured Letter of Credit Facility

Athabasca maintains a $50.0 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, 2020 - $40 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 3.3%. As at December 31, 2021, the Company had $47.8 million of letters of credit issued under the Unsecured Letter of Credit Facility (December 31, 2020 - $39.7 million).

Financing and Interest

($ Thousands)	Three months ended December 31, 2021	2020	Year ended December 31, 2021	2020
Financing and interest expense on indebtedness	$ 15,570	$ 14,876	$ 59,151	$ 61,709
Financing fees expense - warrant issuance costs allocation	1,488	—	1,488	—
Accretion of 2022 Notes	4,917	2,706	13,442	10,700
Accretion of 2026 Notes	3,366	—	3,366	—
Accretion of warrants	153	—	153	—
Accretion of provisions	3,656	3,284	14,007	12,513
Interest expense on lease liability	275	345	1,209	1,480
TOTAL FINANCING AND INTEREST	$ 29,425	$ 21,211	$ 92,816	$ 86,402

During the three months and year ended December 31, 2021 and 2020, financing and interest expenses were primarily attributable to the Company's term debt. Finance and interest expense on indebtedness was higher for the three months ended December 31, 2021 due to higher debt balances outstanding during the redemption period for the 2022 Notes. Accretion of 2022 Notes increased for this period as a result of the early redemption of the 2022 Notes.

Foreign Exchange Gain (Loss), Net

($ Thousands)	Three months ended December 31, 2021	2020	Year ended December 31, 2021	2020
Unrealized foreign exchange gain (loss)	$ (33,045)	$ 22,640	$ (25,637)	$ 4,454
Realized foreign exchange gain (loss)	34,713	47	33,063	2,270
FOREIGN EXCHANGE GAIN (LOSS), NET	$ 1,668	$ 22,687	$ 7,426	$ 6,724

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 and deposits. 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, 2021, 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 2022	7,300 bbl/d	$ 63.39 - 122.78	$ 50.00 - 96.84
WTI collar	April - June 2022	9,300 bbl/d	$ 63.39 - 121.83	$ 50.00 - 96.09
WTI collar	July - December 2022	11,300 bbl/d	$ 63.39 - 120.90	$ 50.00 - 95.37
WTI collar	January - March 2023	13,750 bbl/d	$ 66.39 - 102.91	$ 52.36 - 81.17
WCS fixed price swap	January - March 2022	16,000 bbl/d	$ 69.42	$ 54.75
WCS fixed price swap	April - June 2022	14,000 bbl/d	$ 68.45	$ 53.99
WCS fixed price swap	July - December 2022	12,000 bbl/d	$ 67.91	$ 53.57
Purchase contracts			*C$/GJ*	*US$/GJ*
AECO fixed price swaps	January - December 2022	26,000 GJ/d	$ 4.05	$ 3.19

(1) The implied C$ or US$ Average Price per bbl or GJ, as applicable, was calculated using the December 31, 2021 exchange rate of US$1.00 = C$1.2678.

The following table summarizes the Company's net gain (loss) on commodity risk management contracts for the three months and year ended December 31, 2021 and 2020:

($ Thousands)	Three months ended December 31, 2021	Three months ended December 31, 2020	Year ended December 31, 2021	Year ended December 31, 2020
Unrealized gain (loss) on commodity risk mgmt. contracts	$ 28,515	$ 4,886	$ (34,083)	$ 13,329
Realized gain (loss) on commodity risk mgmt. contracts	(44,913)	(9,353)	(111,689)	29,149
GAIN (LOSS) ON COMMODITY RISK MGMT. CONTRACTS, NET	$ (16,398)	$ (4,467)	$ (145,772)	$ 42,478

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

As at December 31, 2021	Change in WTI: Increase of US$5.00/bbl	Change in WTI: Decrease of US$5.00/bbl	Change in WCS differential: Increase of US$1.00/bbl	Change in WCS differential: Decrease of US$1.00/bbl
Increase (decrease) to fair value of commodity risk management contracts	$ (30,241)	$ 30,241	$ 5,957	$ (5,957)

Additional financial commodity risk management has taken place subsequent to December 31, 2021, 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	April - June 2022	9,300 bbl/d	$ 121.83 - 139.46	$ 96.09 - 110.00
WTI collar	July - December 2022	11,300 bbl/d	$ 120.90 - 139.46	$ 95.37 - 110.00
WTI/WCS differential swaps	April - September 2022	2,500 bbl/d	$ 15.53	$ 12.25

(1) The implied C$ or US$ Average Price/bbl, as applicable, was calculated using the December 31, 2021 exchange rate of US$1.00 = C$1.2678.

Commitments and Contingencies

The following table summarizes Athabasca's estimated future unrecognized minimum commitments as at December 31, 2021 for the following five years and thereafter:

($ Thousands)	2022	2023	2024	2025	2026	Thereafter	Total
Transportation and processing[(1)]	$ 119,416	$ 117,427	$ 112,356	$ 108,468	$ 107,901	$1,145,094	$1,710,662
Interest expense on term debt[(1)]	43,264	43,264	43,264	43,264	36,052	—	209,108
Purchase commitments	13,053	—	—	—	—	—	13,053
TOTAL COMMITMENTS	$ 175,733	$ 160,691	$ 155,620	$ 151,732	$ 143,953	$1,145,094	$1,932,823

(1) Commitments which are denominated in US dollars were translated into Canadian dollars at the December 31, 2021 exchange rate of US$1.00 = C$1.2678.

In the first quarter of 2021 the shipper agreements on the Keystone XL pipeline were terminated, therefore, the related transportation commitments of $529.1 million were removed from the above disclosure.

In the second quarter of 2021 the Hangingstone transportation and storage service agreement was amended and the related transportation commitments were reduced by $97.7 million.

In the third quarter of 2021 Athabasca executed a sale and assignment agreement of its 20,000 bbl/d Trans Mountain Expansion Project pipeline service. In the third quarter Athabasca also assigned its Keystone base service of 7,200 bbl/d to an industry counterparty and entered into a seven-year marketing agreement with the counterparty for 15,000 bbl/d. The marketing agreement has a pricing derivative when the Gulf Coast service becomes available that currently has no value but will be reassessed at future balance sheet dates. As a result of these third quarter transactions, the related service commitments were reduced by $1.4 billion.

The Company is, from time to time, involved in claims arising in the normal course of business. The Company is also currently undergoing income tax and partner related audits in the normal course of business. The final outcome of such claims and 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 and accounts receivables as per below:

As at	December 31, 2021	December 31, 2020
Petroleum and natural gas receivables	$ 85,817	$ 55,951
Joint interest billings	2,646	3,135
Risk management (realized), government and other receivables	364	3,442
TOTAL	$ 88,827	$ 62,528

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, 2021. 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, 2021 of $223.1 million (December 31, 2020 - $300.8 million), from a 1.0% change in interest rates, would have an annualized impact of approximately $2.2 million (year ended December 31, 2020 - $3.0 million). The 2026 Notes and letters of credit issued are subject to fixed interest rates and are not exposed to changes in interest rates.

Other Corporate Items

General and Administrative ("G&A")

($ Thousands, unless otherwise noted)	Three months ended December 31, 2021	2020	Year ended December 31, 2021	2020
TOTAL GENERAL AND ADMINISTRATIVE	$ 4,499	$ 5,305	$ 15,946	$ 19,431
G&A per boe[(1)]	$ 1.39	$ 1.68	$ 1.26	$ 1.63

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

In 2021, Athabasca's G&A expenses and G&A per boe decreased compared to the same period in the prior year primarily due to reduced salaries, benefits and professional fees.

Restructuring

On April 2, 2020, the Company decided to suspend its Hangingstone operations due to the significant decline in oil prices combined with the economic uncertainty associated with the ongoing COVID-19 crisis. This suspension involved reducing staff levels, shutting in the well pairs, halting steam injection to the reservoir, and taking measures to preserve the processing facility and pipelines in a safe manner so that it could be re-started at a future date. As a result, the Company incurred $5.7 million of restructuring expenses comprised of shut-in costs and severances in 2020.

Stock Based Compensation

During the three months and year ended December 31, 2021, Athabasca's stock-based compensation expense was $5.2 million and $17.3 million compared to $1.4 million and $2.8 million in the respective prior year periods. The increase is primarily due to the increase in the fair value of the cash settled stock-based compensation plans in 2021 as a result of the increased share price on December 31, 2021.

Gain (Loss) on Revaluation of Provisions and Other, Net

($ Thousands)	Three months ended December 31, 2021	Three months ended December 31, 2020	Year ended December 31, 2021	Year ended December 31, 2020
Provision for pipeline project	$ —	$ (61,590)	$ 60,564	$ (61,590)
Change in fair value of warrant liability	(14,768)	—	(14,768)	—
Change in estimated decommissioning obligations related to fully impaired E&E assets	22,053	1,709	22,053	4,928
Other	151	(1,242)	151	(5,576)
Contingent payment obligation	—	—	—	1,028
Capital-carry receivable	—	—	—	138
TOTAL GAIN (LOSS) ON REVALUATION OF PROVISIONS AND OTHER	$ 7,436	$ (61,123)	$ 68,000	$ (61,072)

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

As at December 31, 2021, Athabasca did not recognize deductible net temporary differences of $2.1 billion (December 31, 2020 - $2.5 billion) primarily consisting of approximately $1.9 billion (December 31, 2020 - $1.8 billion) in non-capital losses and $0.2 billion (December 31, 2020 - $0.7 billion) in Capital Cost Allowance and resource pools in excess of capital assets. The Company has approximately $3.2 billion in tax pools, including approximately $2.4 billion in non-capital losses and exploration tax pools available for immediate deduction against future income. Athabasca Oil Corporation's material non-capital losses have an expiry profile between 2030 and 2040.

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, 2021, there were 530.8 million common shares outstanding, an aggregate of 24.0 million restricted share units and performance share units outstanding, 6.5 million stock options outstanding and 79.5 million potential shares issuable under warrants agreements. During the three months and year ended December 31, 2021, Athabasca issued 0.2 million common shares in respect of the Company's equity-settled share-based compensation plans.

SUMMARY OF QUARTERLY RESULTS

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

	2021				2020			
($ Thousands, unless otherwise noted)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	77.19	70.56	66.07	57.84	42.66	40.93	27.85	46.17
WTI (C$/bbl)	97.25	88.91	81.11	73.24	55.58	54.50	38.59	62.03
Western Canadian Select (C$/bbl)	78.67	71.77	66.96	57.40	43.40	42.39	22.41	34.11
Edmonton Par (C$/bbl)	93.14	83.70	77.07	66.44	49.98	49.54	29.55	51.62
Edmonton Condensate (C5+) (C$/bbl)	99.24	86.78	81.00	72.92	55.05	49.78	29.95	60.39
AECO (C$/GJ)	4.41	3.41	2.93	2.98	2.50	2.12	1.89	1.93
Chicago Citygate (US$/MMBtu)	4.57	4.08	2.79	6.47	2.27	1.83	1.61	1.74
Foreign exchange (USD : CAD)	1.26	1.26	1.23	1.27	1.30	1.33	1.39	1.34
CONSOLIDATED								
Petroleum and natural gas production (boe/d)(1)	35,147	34,255	34,659	34,401	34,233	32,061	27,067	36,557
Realized price (net of cost of diluent) ($/boe)(1)	63.89	60.40	53.76	44.23	33.56	33.62	9.03	15.47
Petroleum, natural gas and midstream sales ($)(2)	305,313	291,300	243,868	221,282	162,815	134,188	56,037	138,500
Operating Income (Loss) ($)(1)	110,648	120,581	93,196	65,928	40,288	50,171	(18,269)	(20,328)
Operating Income (Loss) Net of Realized Hedging ($)(1)	65,735	92,742	75,372	44,815	30,935	42,812	6,166	1,098
Operating Netback ($/boe)(1)	35.43	36.02	31.09	21.12	12.88	17.19	(7.05)	(5.98)
Operating Netback Net of Realized Hedging ($/boe)(1)	21.05	27.70	25.14	14.36	9.89	14.67	2.37	0.33
Capital expenditures ($)	18,352	15,608	22,628	35,554	17,202	12,381	5,811	76,246
Capital Expenditures Net of Capital-Carry ($)(1)	18,352	15,608	22,628	35,554	17,202	12,381	5,811	53,506
THERMAL OIL DIVISION								
Bitumen production (bbl/d)	28,084	26,729	26,433	25,949	24,839	20,231	17,601	28,315
Bitumen sales volumes (bbl/d)	26,889	28,852	24,710	26,240	24,613	19,895	19,045	29,095
Realized bitumen price ($/bbl)(1)	64.40	62.39	55.49	43.83	33.05	33.80	3.83	10.66
Heavy Oil (blended bitumen) and midstream sales ($)	265,076	254,769	207,503	186,710	132,635	97,921	39,231	114,153
Operating Income (Loss) ($)(1)	82,729	94,796	67,568	42,168	20,746	26,844	(24,619)	(33,111)
Operating Netback ($/bbl)(1)	33.43	35.71	30.05	17.85	9.17	14.66	(14.21)	(12.50)
Capital expenditures ($)	12,355	15,228	21,388	33,014	16,915	10,454	4,722	17,696
LIGHT OIL DIVISION								
Petroleum and natural gas production (boe/d)(1)	7,063	7,526	8,226	8,452	9,394	11,830	9,466	8,242
Realized price ($/boe)(1)	61.92	52.76	48.58	45.45	34.92	33.32	19.51	32.46
Petroleum and natural gas sales ($)(2)	40,237	36,531	36,365	34,572	30,180	36,267	16,806	24,347
Operating Income (Loss) ($)(1)	27,919	25,785	25,628	23,760	19,542	23,327	6,350	12,783
Operating Netback ($/boe)(1)	42.95	37.25	34.23	31.24	22.61	21.43	7.37	17.04
Capital expenditures ($)	5,291	128	544	968	117	1,917	1,089	58,527
Capital Expenditures Net of Capital-Carry ($)(1)	5,291	128	544	968	117	1,917	1,089	35,787
OPERATING RESULTS								
Cash flow from operating activities ($)	81,189	75,743	36,183	1,138	16,079	(4,782)	(31,186)	(3,021)
Adjusted Funds Flow ($)(1)	42,643	72,233	50,228	18,961	10,753	14,617	(16,214)	(27,883)
Net income (loss) ($)	384,073	104,951	(13,944)	(17,472)	(56,891)	(18,818)	(65,335)	(516,481)
Net income (loss) per share - basic ($)	0.72	0.20	(0.03)	(0.03)	(0.11)	(0.04)	(0.12)	(0.99)
BALANCE SHEET ITEMS								
Cash and cash equivalents ($)	223,056	273,989	152,639	141,130	165,201	151,730	167,442	199,517
Restricted cash ($)	—	46,107	90,232	135,120	135,624	150,887	152,125	110,634
Total assets ($)	1,742,131	1,510,924	1,466,102	1,443,246	1,425,984	1,425,343	1,468,248	1,599,860
Term debt ($)(3)	384,298	568,428	549,855	555,160	559,498	584,108	594,488	617,123
Shareholders' equity ($)	1,025,959	640,542	534,330	547,035	567,025	622,771	640,515	705,055

(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 2021, 2020 and 2019:

($ Thousands, unless otherwise noted)	December 31, 2021	December 31, 2020	December 31, 2019
Petroleum and natural gas production (boe/d)[1]	34,618	32,483	36,196
Petroleum, natural gas and midstream sales	$ 1,016,323	$ 464,648	$ 836,933
Net income (loss) and comprehensive income (loss)	$ 457,608	$ (657,525)	$ 246,865
per share (basic)	$ 0.86	$ (1.24)	$ 0.47
Cash flow from operating activities	$ 194,253	$ (22,910)	$ 92,632
per share (basic)	$ 0.37	$ (0.04)	$ 0.18
Adjusted Funds Flow[1]	$ 184,065	$ (18,727)	$ 154,760
per share (basic)	$ 0.35	$ (0.04)	$ 0.30
Capital expenditures	$ 92,142	$ 111,640	$ 199,141
Capital Expenditures Net of Capital-Carry[1]	$ 92,142	$ 88,900	$ 140,207
Total assets	$ 1,742,131	$ 1,425,984	$ 2,093,465
Face value of term debt[2]	$ 443,730	$ 572,940	$ 583,425
Weighted average shares outstanding (basic)	530,692,724	528,837,646	521,316,320
Weighted average shares outstanding (diluted)	546,717,181	528,837,646	526,290,689

(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, 2021 is US$350 million (December 31, 2020 and 2019 was US$450 million) and was translated into Canadian dollars at the December 31, 2021 exchange rate of US$1.00 = C$1.2678 (December 31, 2020 US$1.00 = C$1.2732; December 31, 2019 US$1.00 = C$1.2965).

ACCOUNTING POLICIES AND ESTIMATES

During the three months and year ended December 31, 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, 2021 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, 2021, 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).

Judgment was applied in determining the recording of the Provision for the Keystone XL pipeline project (Financial Statement Note 13) and the current/non-current classification of that provision at December 31, 2020.

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.

The provision for income taxes is based on judgments in applying income tax law and estimates on the timing and likelihood of reversal of temporary differences between the accounting and tax bases of assets and liabilities. The provision for income taxes is based on Athabasca's interpretation of the tax legislation and regulations which are also subject to change. Athabasca recognizes a tax provision when a payment to tax authorities is considered more likely than not. 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. As at December 31, 2021 and as at December 31, 2020, Athabasca did not recognize deductible temporary differences in respect of income tax assets (Financial Statement Note 23).

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.

The COVID-19 pandemic and ensuing economic recovery continue to drive the global demand for crude oil and natural gas and related prices, which in turn has had a significant impact on the Company's commodity sales from production. 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 COVID-19 on the economy. Refer to the Consolidated Financial Statement Note 9 "Impairment". At December 31, 2021, Management has incorporated the anticipated impacts of COVID-19 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", "Light Oil Capital Expenditures Net of Capital-Carry", "Thermal Oil Operating Income (Loss)", "Thermal Oil Operating Netback", “Consolidated Operating Income (Loss)", "Consolidated Operating Netback", "Consolidated Operating Income (Loss) Net of Realized Hedging", "Consolidated Operating Netback Net of Realized Hedging", "Consolidated Capital Expenditures Net of Capital-Carry", “Realized Prices”, “Cash Transportation & Marketing Expenses” and “Adjusted EBITDA” 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.

Consolidated Capital Expenditures Net of Capital-Carry and Light Oil Capital Expenditures Net of Capital-Carry

The non-GAAP financial measures Consolidated Capital Expenditures Net of Capital-Carry and Light Oil Capital Expenditures Net of Capital-Carry in this MD&A are calculated in the tables on pages 7 and 13. These measures allow management and others to evaluate the true net cash outflow related to Athabasca's capital expenditures.

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, 2021	Three months ended December 31, 2020	Year ended December 31, 2021	Year ended December 31, 2020
Cash flow from operating activities	$ 81,189	$ 16,079	$ 194,253	$ (22,910)
Restructuring expenses	—	—	—	5,703
Changes in non-cash working capital	(38,794)	(5,614)	(11,872)	(11,670)
Settlement of provisions	248	288	1,684	10,150
ADJUSTED FUNDS FLOW	42,643	10,753	184,065	(18,727)
Total Capital Expenditures Net of Capital-Carry(1)	(18,352)	(17,202)	(92,142)	(88,900)
FREE CASH FLOW	$ 24,291	$ (6,449)	$ 91,923	$ (107,627)

(1) Non-GAAP financial measure. See section above.

Operating Income (Loss) and Operating Netback

The non-GAAP measure Operating Income (Loss) 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 (Loss) by its respective sales volumes. The Operating Income (Loss) 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 (Loss) to its segmented income in *Note 17 - Segmented Information* of the Consolidated Financial Statements for the three months and year ended December 31, 2021. The table on page 10 reconciles Thermal Oil Operating Income (Loss) to its segmented income in *Note 17 - Segmented Information* of the Consolidated Financial Statements for the three months and year ended December 31, 2021.

The non-GAAP measure Consolidated Operating Income (Loss) 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 (Loss) Net of Realized Hedging by the total sales volumes. The Consolidated Operating Income (Loss) 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 (Loss) 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, 2021.

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 News Release 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.

Supplementary Financial Measures

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

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

Production volumes details

		Three months ended December 31,		Year ended December 31,	
Production		**2021**	**2020**	**2021**	**2020**
Greater Placid:					
Condensate NGLs	bbl/d	1,211	1,841	1,375	1,964
Other NGLs	bbl/d	494	523	512	474
Natural gas(1)	mcf/d	13,181	17,900	14,537	16,197
Total Greater Placid	boe/d	3,902	5,347	4,310	5,138
Greater Kaybob:					
Oil(2)	bbl/d	1,885	2,845	2,164	3,117
Other NGLs	bbl/d	342	264	344	311
Natural gas(1)	mcf/d	5,603	5,629	5,969	7,032
Total Greater Kaybob	boe/d	3,161	4,047	3,503	4,600
Light Oil:					
Oil(2)	bbl/d	1,885	2,845	2,164	3,117
Condensate NGLs	bbl/d	1,211	1,841	1,375	1,964
Oil and condensate NGLs	bbl/d	3,096	4,686	3,539	5,081
Other NGLs	bbl/d	836	787	856	785
Natural gas(1)	mcf/d	18,784	23,529	20,506	23,229
Total Light Oil division	boe/d	7,063	9,394	7,813	9,738
Total Thermal Oil division bitumen	bbl/d	28,084	24,839	26,805	22,745
Total Company production	boe/d	35,147	34,233	34,618	32,483

(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.

This MD&A also makes reference to Athabasca's forecasted total average daily production of 33,000 - 34,000 boe/d for 2022. Athabasca expects that approximately 82% of that production will be comprised of bitumen, 8% shale gas, 5% tight oil, 3% condensate natural gas liquids and 2% other natural gas liquids.

Liquids:		Three months ended December 31, 2021	2020	Year ended December 31, 2021	2020
Greater Placid:					
Condensate NGLs	bbl/d	1,211	1,841	1,375	1,964
Other NGLs	bbl/d	494	523	512	474
Total Greater Placid Liquids	bbl/d	1,705	2,364	1,887	2,438
as % of Greater Placid prod.		44%	44%	44%	47%
Greater Kaybob:					
Oil	bbl/d	1,885	2,845	2,164	3,117
Other NGLs	bbl/d	342	264	344	311
Total Greater Kaybob Liquids	bbl/d	2,227	3,109	2,508	3,428
as % of Greater Kaybob prod.		70%	77%	72%	75%
Total Light Oil:					
Oil and condensate NGLs	bbl/d	3,096	4,686	3,539	5,081
Other NGLs	bbl/d	836	787	856	785
Total Light Oil division Liquids	bbl/d	3,932	5,473	4,395	5,866
as % of Light Oil production		56%	58%	56%	60%
Total Company:					
Total Light Oil division Liquids	bbl/d	3,932	5,473	4,395	5,866
Total Thermal Oil division bitumen	bbl/d	28,084	24,839	26,805	22,745
Total Company Liquids	bbl/d	32,016	30,312	31,200	28,611
as % of Company production		91%	89%	90%	88%

Comparative Figures

Certain comparative figures have been restated to conform to the current period presentation.

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, 2021, 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, 2021, 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, 2021.

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;
- operational impacts related to COVID-19 (coronavirus);
- 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," "plan," "continue", "estimate", "expect", "may", "will", "project", "target", "should", "believe", "predict", "pursue" and "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; the Company's anticipated sources of funding for 2022 and beyond; the Company's estimated future minimum commitments; the future allocation of capital; Adjusted EBITDA; 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, 2021 (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; continued impact of the COVID-19 pandemic; state of capital markets; ability to finance capital requirements; access to capital and insurance; abandonment and reclamation costs; changing demand for oil and natural gas products; anticipated benefits of acquisitions and dispositions; royalty regimes; foreign exchange rates and interest rates; reserves; hedging; operational dependence; operating costs; project risks; supply chain disruption; financial assurances; diluent supply; third party credit risk; indigenous claims; reliance on key personnel and operators; income tax; cybersecurity; advanced technologies; hydraulic fracturing; liability management; seasonality and weather conditions; unexpected events; internal controls; limitations 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, 2021. 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 on page 11 of this MD&A include: 7 proved undeveloped locations and 78 probable undeveloped locations for a total of 85 booked locations with the balance being unbooked locations. The 150 Montney drilling locations referenced on page 11 of this MD&A include: 39 proved undeveloped locations and 59 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, 2021 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, 2021, 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