Management's Discussion and Analysis

December 31, 2020

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 3, 2021 and should be read in conjunction with the audited consolidated financial statements of the Company for the years ended December 31, 2020 and 2019. 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 3, 2021 ("AIF"). The Company's common shares are listed on the Toronto Stock Exchange under the trading symbol "ATH".

FOCUSED | EXECUTING | DELIVERING

ATHABASCA'S STRATEGY

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

- Light Oil - Montney at Placid ("Greater Placid") and Duvernay at Kaybob ("Greater Kaybob"): High Margin Liquids Rich Development
- Thermal Oil: Low Decline Production
- Financial Sustainability: Flexible Capital, Strong Liquidity

Athabasca remains focused on maximizing corporate funds flow and maintaining corporate liquidity. Athabasca maintains 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, 2020

In March 2020, the COVID-19 outbreak was declared a pandemic by the World Health Organization. Global commodity prices declined significantly due to a reduction in oil demand as countries around the world, including Canada, enacted emergency measures to combat the spread of the virus. Throughout the second half of 2020, economies have started to reopen along with positive developments on the vaccine front leading to a strong recovery in oil prices.

Corporate

- Fourth quarter production of 34,233 boe/d (89% Liquids(1)) and 2020 production of 32,483 boe/d (88% Liquids(1)).
- Operating Income(1) of $30.9 million in the fourth quarter and $81.0 million for 2020.
- Fourth quarter Adjusted Funds Flow(1) of $10.8 million.
- $165.2 million of unrestricted cash at December 31, 2020.
- 1.2 billion boe Proved plus Probable reserves, with Leismer/Corner underpinning 1 billion barrels of low risk, long reserve life resource.

Light Oil Division

- Fourth quarter production of 9,394 boe/d (58% Liquids(1)) and 2020 production of 9,738 boe/d (60% Liquids(1)).
- Fourth quarter Operating Income(1) of $19.5 million and 2020 Operating Income(1) of $62.0 million.
- Fourth quarter and 2020 Operating Netbacks(1) of $22.61/boe and $17.40/boe.
- Capital expenditures net of the capital carry(1) of $38.9 million for 2020 which included the tie-in of 10 gross Montney wells and 17 gross Duvernay wells.

Thermal Oil Division

- Fourth quarter bitumen production of 24,839 bbl/d and 2020 production of 22,745 bbl/d.
- Strong reservoir response at Hangingstone with current production of approximately 8,800 bbl/d (February 2021).
- Operating income(1) in the fourth quarter of $20.7 million.
- Operating Netbacks(1) of $9.17/bbl in the fourth quarter ($13.20/bbl at Leismer) were supported by the improvement in commodity prices.
- Capital expenditures of $49.8 million for 2020, including $16.9 million in the fourth quarter for routine pump replacements and progressing drilling initiatives for 2021 to sustain production at Leismer.

(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, 2020	Three months ended December 31, 2019	Year ended December 31, 2020	Year ended December 31, 2019
CONSOLIDATED				
Petroleum and natural gas production (boe/d)(1)	34,233	36,403	32,483	36,196
Operating Income (Loss)(1)(2)	$ 30,935	$ 42,881	$ 81,011	$ 233,219
Operating Netback(1)(2) ($/boe)	$ 9.89	$ 13.84	$ 6.73	$ 17.95
Capital expenditures	$ 17,202	$ 69,796	$ 111,640	$ 199,141
Capital Expenditures Net of Capital-Carry(1)	$ 17,202	$ 46,259	$ 88,900	$ 140,207
LIGHT OIL DIVISION				
Petroleum and natural gas production (boe/d)(1)	9,394	8,642	9,738	10,138
Percentage Liquids (%)(1)	58%	54%	60%	54%
Operating Income (Loss)(1)	$ 19,542	$ 16,287	$ 62,002	$ 95,004
Operating Netback(1) ($/boe)	$ 22.61	$ 20.49	$ 17.40	$ 25.68
Capital expenditures	$ 117	$ 46,473	$ 61,651	$ 109,687
Capital Expenditures Net of Capital-Carry(1)	$ 117	$ 22,936	$ 38,911	$ 50,753
THERMAL OIL DIVISION				
Bitumen production (bbl/d)	24,839	27,761	22,745	26,058
Operating Income (Loss)(1)	$ 20,746	$ 28,658	$ (10,140)	$ 182,196
Operating Netback(1) ($/bbl)	$ 9.17	$ 12.44	$ (1.19)	$ 19.59
Capital expenditures	$ 16,915	$ 23,229	$ 49,787	$ 89,343
CASH FLOW AND FUNDS FLOW				
Cash flow from operating activities	$ 16,079	$ 32,975	$ (22,910)	$ 92,632
per share - basic	$ 0.03	$ 0.06	$ (0.04)	$ 0.18
Adjusted Funds Flow(1)	$ 10,753	$ 21,478	$ (18,727)	$ 154,760
per share - basic	$ 0.02	$ 0.04	$ (0.04)	$ 0.30
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)				
Net income (loss) and comprehensive income (loss)	$ (56,891)	$ (8,757)	$ (657,525)	$ 246,865
per share - basic	$ (0.11)	$ (0.02)	$ (1.24)	$ 0.47
per share - diluted	$ (0.11)	$ (0.02)	$ (1.24)	$ 0.47
COMMON SHARES OUTSTANDING				
Weighted average shares outstanding - basic	530,675,391	523,428,276	528,837,646	521,316,320
Weighted average shares outstanding - diluted	533,453,490	523,428,276	528,837,646	526,290,689

As at ($ Thousands)	December 31, 2020	December 31, 2019
LIQUIDITY AND BALANCE SHEET		
Cash and cash equivalents	$ 165,201	$ 254,389
Restricted cash	$ 135,624	$ 110,609
Available credit facilities(3)	$ 348	$ 85,815
Capital-carry receivable (undiscounted)	$ —	$ 22,740
Face value of long-term debt(4)	$ 572,940	$ 583,425

(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 $9.4 million and gain of $29.1 million for the three months and year ended December 31, 2020, respectively (three months and year ended December 31, 2019 - $2.1 million loss and $44.0 million loss).
(3) Includes available credit under Athabasca's Credit Facility and Unsecured Letter of Credit Facility (see page 15).
(4) The face value of the 2022 Notes is US$450 million. The 2022 Notes were translated into Canadian dollars at the December 31, 2020 exchange rate of US$1.00 = C$1.2732 (2019 – C$1.2965).

INDEPENDENT RESERVES EVALUATION

The Company's qualified independent reserve evaluators, McDaniel & Associates Consultants Ltd. ("McDaniel"), completed independent reserve evaluations effective December 31, 2020 and 2019. 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 3, 2021, for further details relating to Athabasca's reserves.

Reserves

At December 31, 2020, the Company had 1,156 MMboe of Proved plus Probable Reserves (December 31, 2019 - 1,297 MMboe). The following table shows the Company's reserves by division (tables may not add due to rounding):

	December 31, 2020			December 31, 2019		
Reserves	Proved Developed Producing	Proved	Proved plus Probable	Proved Developed Producing	Proved	Proved plus Probable
Light Oil Division[1]						
Greater Placid (MMboe)	8	30	49	7	33	49
Greater Kaybob (MMboe)	7	8	25	6	13	23
Total Light Oil Division (MMboe)	14	37	73	13	46	72
Thermal Oil Division[2]						
Leismer (MMbbl)	29	333	694	34	331	695
Corner (MMbbl)	—	—	353	—	—	353
Hangingstone (MMbbl)	32	32	36	35	80	177
Total Thermal Oil Division (MMbbl)	61	365	1,083	68	410	1,225
Consolidated reserves (MMboe)	76	403	1,156	81	456	1,297

(1) 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.
(2) Thermal Oil reserves are comprised of bitumen.

In the Light Oil Division, reserves were relatively consistent year-over-year with 73 MMboe of Proved plus Probable (“2P”). 2P Liquids weighting increased to 56% (from 53%) driven by Duvernay development plans focused on the volatile oil window.

In the Thermal Oil Division, the Proved Developed Producing (“PDP”) reserves decreased by 10% to 61 MMbbl due to 2020 production and no new drilling activity. 2P reserves decreased 12% from 1,225 MMbbl to 1,083 MMbbl for the year ended December 31, 2020. The reduction was primarily due to the undeveloped reserves at Hangingstone becoming uneconomic when run on the year-end third party reserve price forecasts.

BUSINESS ENVIRONMENT AND THE IMPACT OF COVID-19

Benchmark prices

(Average)	Three months ended December 31, 2020	2019	Change	Year ended December 31, 2020	2019	Change
Crude oil:						
West Texas Intermediate (WTI) (US$/bbl)[1]	$ 42.66	$ 56.96	(25) %	$ 39.40	$ 57.03	(31) %
West Texas Intermediate (WTI) (C$/bbl)[1]	$ 55.58	$ 75.19	(26) %	$ 52.81	$ 75.70	(30) %
Western Canadian Select (WCS) (C$/bbl)[2]	$ 43.40	$ 54.27	(20) %	$ 35.58	$ 58.75	(39) %
Edmonton Par (C$/bbl)[3]	$ 49.98	$ 67.99	(26) %	$ 45.17	$ 69.05	(35) %
Edmonton Condensate (C5+) (C$/bbl)[4]	$ 55.05	$ 69.22	(20) %	$ 48.79	$ 69.58	(30) %
WCS Differential:						
to WTI (US$/bbl)	$ (9.30)	$ (15.83)	(41) %	$ (12.60)	$ (12.76)	(1) %
to WTI (C$/bbl)	$ (12.18)	$ (20.92)	(42) %	$ (17.23)	$ (16.95)	2 %
Edmonton Par Differential:						
to WTI (US$/bbl)	$ (4.07)	$ (5.37)	(24) %	$ (5.33)	$ (4.88)	9 %
to WTI (C$/bbl)	$ (5.60)	$ (7.20)	(22) %	$ (7.64)	$ (6.65)	15 %
Natural gas:						
AECO (C$/GJ)[5][6]	$ 2.50	$ 2.35	6 %	$ 2.11	$ 1.67	26 %
Chicago Citygate (US$/MMBtu)[6]	$ 2.27	$ 2.20	3 %	$ 1.86	$ 2.35	(21) %
Foreign exchange:						
USD : CAD	1.3029	1.3201	(1) %	1.3403	1.3273	1 %

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.

The COVID-19 pandemic that began in March 2020 had a significant negative impact on global commodity prices due to a reduction in oil demand as countries around the world enacted emergency measures to combat the spread of the virus. The Company took swift action in response to the pandemic and the economic crisis. Major initiatives included a reduction to the 2020 capital program, temporary production curtailments, partnering with service companies to reduce operating costs and reducing future financial commitments on the Keystone XL pipeline (“KXL”).

In the second half of 2020, commodity prices began to improve with both OPEC+ and North American producers reducing production allowing for global inventories to fall. Economies have started to reopen with positive developments on the vaccine front and world oil demand has almost recovered to pre-pandemic levels. Supply and demand fundamentals are now supporting a much stronger oil futures market.

In Alberta, physical markets and regional benchmark prices (e.g. WCS heavy oil) have also strengthened with WTI prices and tighter differentials as a result of curtailed volumes and falling inventories. Athabasca expects current WCS differentials to remain supported by muted industry growth projects, significant second quarter turnaround programs in the oil sands, and improving basin egress (including Enbridge Line 3 replacement in the second half of 2021). There is strong demand for heavy oil from US Gulf Coast refineries as they face structural declines in global heavy oil supply (Venezuela and Mexico). Athabasca believes conditions are emerging for WCS heavy oil to be among the most valuable global crude benchmarks.

OUTLOOK

Athabasca is forecasting a 2021 capital budget of $100 million ($95 million Thermal Oil and $5 million Light Oil) with activity focused on sustaining production at the Company's cornerstone Leismer asset. The updated budget reflects $25 million for the increased scope of drilling and commissioning Pad L8 at Leismer. The capital program will support base production levels in the second half of 2021 and beyond. The program is anticipated to be fully funded within 2021 forecasted funds flow with upside potential at current strip pricing. Annual production guidance is maintained between 31,000 – 33,000 boe/d (90% Liquids).

2021 Operational & Financial Guidance ($ millions, unless otherwise noted)	Annual
Production (boe/d)(1)	31,000 - 33,000
% Liquids	~90%
Capital Expenditures(2)	$100
Light Oil	$5
Thermal Oil	$95

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on production disclosure.
(2) Excludes capitalized G&A and stock based compensation.

Athabasca plans to refinance its US$450 million Second Lien Notes during the year as energy credit markets continue to improve. The Company maintains liquidity of $165 million at year-end 2020 that is forecasted to grow through the second half of 2021 with a front-end weighted capital program. The Company intends to remain nimble and creative in accessing the credit capital markets which could include a combination of term debt and bank debt to optimize its current capital structure. The Company's goals include providing multi-year funding certainty and lowering the overall quantum and cost of debt.

2020 Guidance Review

Athabasca updated its original 2020 production and capital expenditures guidance throughout the year in response to the significant decline in oil prices and economic uncertainty associated to the ongoing COVID-19 crisis. Key actions taken included a reduction to the capital program, the Hangingstone shut-in and restart, voluntary production curtailments at Leismer and Placid, and operating cost reduction initiatives across the organization, amongst other actions.

2020 Guidance	Original Guidance	Updated Guidance				Actual
($ millions, unless otherwise noted)	Jan. 8, 2020	Apr. 2, 2020	Apr. 28, 2020	Jul. 29, 2020	Dec. 2, 2020	Full year
Production (boe/d)(1)	36,000-37,500	30,000-31,500	Withdrawn	Q4 32,000-34,000	32,250	32,483
Capital Expenditures Net of Capital-Carry(1)(2)	$125	$85	$85	$85	$85	$83
Adjusted Funds Flow(1)	$125	Withdrawn	—	—	—	$(19)

(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) Excludes capitalized G&A and stock based compensation.
(3) The Company suspended its guidance given the uncertainty associated with the duration of curtailments which were dictated by commodity prices.

CONSOLIDATED RESULTS

For analysis of operating results see the Light Oil Division and Thermal 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, 2020	2019	Year ended December 31, 2020	2019
PRODUCTION				
Oil and condensate (bbl/d)[1]	4,686	3,793	5,081	4,507
Natural gas (Mcf/d)[1]	23,529	23,695	23,229	28,281
Other natural gas liquids (bbl/d)[1]	787	899	785	918
Bitumen (bbl/d)	24,839	27,761	22,745	26,058
Total (boe/d)[1]	34,233	36,403	32,483	36,196

(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, 2020	2019	Year ended December 31, 2020	2019
Petroleum and natural gas sales[1]	$ 162,815	$ 188,101	$ 491,540	$ 855,097
Royalties	(1,843)	(3,761)	(6,090)	(16,183)
Cost of diluent[1]	(57,806)	(68,428)	(212,400)	(286,957)
Operating expenses	(39,184)	(46,342)	(137,357)	(173,601)
Transportation and marketing	(23,694)	(24,625)	(83,831)	(101,156)
	$ 40,288	$ 44,945	$ 51,862	$ 277,200
Realized gain (loss) on commodity risk management contracts	(9,353)	(2,064)	29,149	(43,981)
Consolidated Operating Income (Loss)[2]	$ 30,935	$ 42,881	$ 81,011	$ 233,219
REALIZED PRICES				
Oil and condensate ($/bbl)	$ 50.89	$ 67.38	$ 43.82	$ 67.21
Natural gas ($/Mcf)	2.82	2.82	2.34	2.55
Other natural gas liquids ($/bbl)	29.43	27.21	21.60	30.28
Heavy oil (Blended bitumen) ($/bbl)	41.51	48.55	32.15	54.35
Realized price (net of cost of diluent) ($/boe)	33.56	38.61	23.19	43.70
Royalties ($/boe)	(0.59)	(1.21)	(0.51)	(1.24)
Operating expenses ($/boe)	(12.52)	(14.95)	(11.41)	(13.35)
Transportation and marketing ($/boe)	(7.57)	(7.94)	(6.96)	(7.78)
	$ 12.88	$ 14.51	$ 4.31	$ 21.33
Realized gain (loss) on commodity risk mgmt. contracts ($/boe)	(2.99)	(0.67)	2.42	(3.38)
CONSOLIDATED OPERATING NETBACK[2] ($/boe)	$ 9.89	$ 13.84	$ 6.73	$ 17.95

(1) 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) 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, 2020	2019	Year ended December 31, 2020	2019
Consolidated Operating Income (Loss)[1]	$ 30,935	$ 42,881	$ 81,011	$ 233,219
Unrealized gain (loss) on commodity risk management contracts	4,886	(3,634)	13,329	(2,437)
Impairment loss	—	—	(471,839)	—
Depletion and depreciation	(25,495)	(30,883)	(110,078)	(128,854)
Gain (loss) on sale of assets	58	105	21,289	222,653
Exploration and non-producing asset expenses	(514)	(384)	(22,410)	(2,330)
CONSOLIDATED SEGMENTS INCOME (LOSS)	$ 9,870	$ 8,085	$ (488,698)	$ 322,251

(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, 2020	2019	Year ended December 31, 2020	2019
Light Oil Division	$ 117	$ 46,473	$ 61,651	$ 109,687
Thermal Oil Division	16,915	23,229	49,787	89,343
Corporate assets	170	94	202	111
TOTAL CAPITAL EXPENDITURES(1)	$ 17,202	$ 69,796	$ 111,640	$ 199,141
Less: Greater Kaybob capital-carry	—	(23,537)	(22,740)	(58,934)
TOTAL CAPITAL EXPENDITURES NET OF CAPITAL-CARRY(2)	$ 17,202	$ 46,259	$ 88,900	$ 140,207

(1) For the three months ended December 31, 2020, capital expenditures include capitalized cash staff costs of $1.2 million (three months ended December 31, 2019 - $2.1 million). For the year ended December 31, 2020, capital expenditures include cash capitalized staff costs of $5.6 million (year ended December 31, 2019 - $8.6 million) and cash capitalized Phantom Share Unit costs of $0.2 million (year ended December 31, 2019 - $nil).

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

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, 2020, the Light Oil Division had approximately 73 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 90,000 gross Montney acres. Athabasca has transitioned Greater Placid from early stage resource capture to efficient multi-well pad development. An inventory of approximately 150(2) gross drilling locations positions the Company for multi-year development.

In Greater Kaybob, Athabasca has a 30% non-operated interest in approximately 215,000 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. 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, 2020. 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, 2020	2019	Year ended December 31, 2020	2019
PRODUCTION[1]				
Oil and condensate (bbl/d)	4,686	3,793	5,081	4,507
Natural gas (Mcf/d)	23,529	23,695	23,229	28,281
Other natural gas liquids (bbl/d)	787	899	785	918
Total (boe/d)	9,394	8,642	9,738	10,138
Consisting of:				
Greater Placid area (boe/d)	5,347	4,571	5,138	5,680
% Liquids	44%	43%	47%	44%
Greater Kaybob area (boe/d)	4,047	4,071	4,600	4,458
% Liquids	77%	67%	75%	65%

(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, 2020	2019	Year ended December 31, 2020	2019
Petroleum and natural gas sales	$ 30,180	$ 31,904	$ 107,600	$ 146,980
Royalties	(1,286)	(1,273)	(3,940)	(4,638)
Operating expenses	(6,856)	(8,719)	(27,883)	(26,234)
Transportation and marketing	(2,496)	(5,625)	(13,775)	(21,104)
Light Oil Operating Income (Loss)[1]	$ 19,542	$ 16,287	$ 62,002	$ 95,004
REALIZED PRICES				
Oil and condensate ($/bbl)	$ 50.89	$ 67.38	$ 43.82	$ 67.21
Natural gas ($/Mcf)	2.82	2.82	2.34	2.55
Other natural gas liquids ($/bbl)	29.43	27.21	21.60	30.28
Realized price ($/boe)	34.92	40.13	30.19	39.72
Royalties ($/boe)	(1.49)	(1.60)	(1.11)	(1.25)
Operating expenses ($/boe)	(7.93)	(10.97)	(7.82)	(7.09)
Transportation and marketing ($/boe)	(2.89)	(7.07)	(3.86)	(5.70)
LIGHT OIL OPERATING NETBACK[1] ($/boe)	$ 22.61	$ 20.49	$ 17.40	$ 25.68

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

Athabasca's Light Oil production averaged 9,394 boe/d and 9,738 boe/d during the three months and year ended December 31, 2020. Production during the fourth quarter of 2020 was higher than the fourth quarter of 2019 as production from 10 (gross) new Montney development wells in Greater Placid and 17 (gross) new Duvernay development wells in Greater Kaybob was brought on-stream during the year, partially offset by natural production declines on existing wells.

Athabasca generated Light Oil Operating Income of $19.5 million ($22.61/boe operating netback) in the fourth quarter of 2020 and $62.0 million in 2020 ($17.40/boe operating netback). The fourth quarter 2020 operating netback was 10% higher compared to fourth quarter 2019 due to lower transportation and marketing costs with contracts ending and mitigation of unutilized transportation. Full year operating netbacks decreased from the comparable period in 2019 primarily due to lower oil and condensate benchmark commodity prices.

Light Oil Segment Income (Loss)

($ Thousands)	Three months ended December 31, 2020	2019	Year ended December 31, 2020	2019
Light Oil Operating Income (Loss)(1)	$ 19,542	$ 16,287	$ 62,002	$ 95,004
Impairment loss	—	—	(263,955)	—
Depletion and depreciation	(14,378)	(16,278)	(63,166)	(71,322)
Gain (loss) on sale of assets	—	—	—	(1,205)
LIGHT OIL SEGMENT INCOME (LOSS)	$ 5,164	$ 9	$ (265,119)	$ 22,477

(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.

Depletion and depreciation decreased in 2020 compared to the same periods in the prior year, primarily due the impairment in the first quarter of 2020.

Light Oil Capital Expenditures

($ Thousands)	Three months ended December 31, 2020	2019	Year ended December 31, 2020	2019
Greater Placid	$ (284)	$ 14,953	$ 22,029	$ 30,214
Greater Kaybob	401	31,520	39,622	79,473
TOTAL LIGHT OIL CAPITAL EXPENDITURES(1)(2)	$ 117	$ 46,473	$ 61,651	$ 109,687
Less: Greater Kaybob capital-carry	—	(23,537)	(22,740)	(58,934)
TOTAL CAPITAL EXPENDITURES NET OF CAPITAL-CARRY(3)	$ 117	$ 22,936	$ 38,911	$ 50,753

(1) For the three months and year ended December 31, 2020, capital expenditures include $0.5 million and $2.5 million of capitalized cash staff costs, respectively (three months and year ended December 31, 2019 - $0.9 million and $3.8 million, respectively).
(2) Includes $7.0 million of net land acquisition expenditures in 2019.
(3) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

Including recovery of the capital-carry, Athabasca's net cash outflow from capital expenditures in the Greater Kaybob area was $0.4 million and $16.9 million for the three months and year ended December 31, 2020, respectively (three months and year ended December 31, 2019 – $8.0 million and $20.5 million).

During the year ended 2020, Light Oil capital expenditures of $61.7 million, $38.9 million net of the capital-carry, were primarily incurred for drilling and completions in the first quarter. The following table summarizes Athabasca's well activity for the three months and year ended December 31, 2020 and 2019:

	Three months ended December 31,				Year ended December 31,			
	2020		2019		2020		2019	
Well activity(1)	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Greater Placid								
Wells drilled	—	—	4	2.8	—	—	4	2.8
Wells completed	—	—	3	2.1	7	4.9	3	2.1
Wells brought on production	—	—	—	—	10	7.0	—	—
Greater Kaybob								
Wells drilled	—	—	9	2.4	8	2.4	18	5.1
Wells completed	—	—	3	0.8	13	3.7	14	4.1
Wells brought on production	—	—	—	—	17	4.9	10	3.0

(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.

THERMAL OIL DIVISION

Overview

Athabasca's Thermal Oil Division consists of its cornerstone producing Leismer asset and a large resource base of expansion and exploration areas 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 potential.

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 45 years and a reserve life index of over 90 years (proved plus probable). The Leismer Project has Proved plus Probable Reserves of approximately 694 MMbbl(1) and Best Estimate Development Pending Contingent Resources of 319 MMbbl (risked)(1) (354 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 Project and Corner assets have received regulatory approval for future development phases of up to a combined 80,000 bbl/d.

Athabasca also has a 100% working interest in the Hangingstone Thermal Oil Project (the "Hangingstone Project"). The Hangingstone Project was commissioned in July 2015 and has Proved plus Probable Reserves of approximately 36 MMbbl(1). On April 2, 2020, the Company suspended operations in response to unprecedented low oil prices and significant economic uncertainty associated with the COVID-19 crisis. During the summer Athabasca completed a planned turnaround. The Hangingstone Project was restarted on September 1, 2020 in response to improved oil prices.

Athabasca's Thermal Oil exploration areas consist of Dover West Leduc Carbonates and Dover West Sands, with oil sands prospectively in the McMurray and Wabiskaw formations as well as carbonates in the Leduc formation.

Athabasca's Thermal Oil Division has access to multiple sales points with marketing agreements on the Enbridge Waupisoo transportation pipeline and has approximately 7,200 bbl/d of blended bitumen capacity on the existing Keystone pipeline diversifying its end market access to the US Gulf Coast. Longer term, Athabasca has secured 20,000 bbl/d of blended bitumen capacity on the Trans Mountain pipeline expansion and 10,000 bbl/d of blended bitumen capacity on the Keystone XL pipeline which will further diversify the Company's access to multiple end markets.

In 2016 and 2017, Athabasca granted Contingent Bitumen Royalties on its Thermal Oil assets to Burgess Energy Holdings L.L.C. ("Burgess") for gross cash proceeds of $397 million. On April 28, 2020, Athabasca upsized the Contingent Bitumen Royalty with Burgess for additional cash consideration of $70 million, bringing the total cash raised to $467 million. The Royalty structure ensures the Thermal Oil assets are not encumbered at low commodity prices. The Royalty on the brownfield assets (Leismer, Hangingstone and Corner) is 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. On the greenfield Dover West asset the Royalty structure is based on a scale from 0% – 12% with a WCS heavy benchmark. At prices below US$70 WCS the rate is 0%. The minimum 2% rate is triggered at US$70 WCS with a sliding scale up to 12% at US$150 WCS. The Royalty is applied to Athabasca's realized bitumen price (C$), which is determined net of storage and transportation costs. The Royalty has no associated commitments to develop future expansions or projects. The Royalty is not expected to materially impact economics of future expansion phases or development projects. No amounts have been paid or are currently payable in respect of the Royalty to Burgess.

(1) Based on the report of Athabasca's independent reserve evaluator effective December 31, 2020. 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, 2020	2019	Year ended December 31, 2020	2019
VOLUMES				
Bitumen production (bbl/d)	17,379	19,296	18,264	17,565
Bitumen sales (bbl/d)	17,241	18,462	18,320	17,402
Heavy oil (blended bitumen) sales (bbl/d)	24,033	25,506	25,519	24,006

($ Thousands, unless otherwise noted)	Three months ended December 31, 2020	2019	Year ended December 31, 2020	2019
Heavy oil (blended bitumen) sales	$ 92,192	$ 114,093	$ 300,923	$ 475,613
Cost of diluent	(38,939)	(48,038)	(155,797)	(184,076)
Total bitumen sales	53,253	66,055	145,126	291,537
Royalties	(429)	(1,979)	(1,835)	(8,422)
Operating expenses - non-energy	(11,695)	(16,272)	(46,227)	(63,739)
Operating expenses - energy	(8,489)	(9,138)	(31,322)	(28,660)
Transportation and marketing	(11,706)	(10,898)	(45,545)	(42,447)
Leismer Operating Income (Loss)(1)	$ 20,934	$ 27,768	$ 20,197	$ 148,269
REALIZED PRICE				
Heavy oil (blended bitumen) sales ($/bbl)	$ 41.70	$ 48.62	$ 32.22	$ 54.28
Bitumen sales ($/bbl)	$ 33.57	$ 38.89	$ 21.64	$ 45.90
Royalties ($/bbl)	(0.27)	(1.17)	(0.27)	(1.33)
Operating expenses - non-energy ($/bbl)	(7.37)	(9.58)	(6.89)	(10.03)
Operating expenses - energy ($/bbl)	(5.35)	(5.38)	(4.67)	(4.51)
Transportation and marketing ($/bbl)	(7.38)	(6.42)	(6.79)	(6.68)
LEISMER OPERATING NETBACK(1) ($/bbl)	$ 13.20	$ 16.34	$ 3.02	$ 23.35

(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 higher Leismer bitumen production in 2020 is primarily due to the start-up up of Pad L7 in the last quarter of 2019 along with the strong plant reliability. Leismer bitumen production in the fourth quarter of 2020 was lower than the same quarter in 2019 due to natural declines and downtime for routine pump replacements.

The Leismer Operating Netback was $13.20/bbl during the fourth quarter of 2020 compared to $16.34/bbl in the fourth quarter of 2019 primarily due to lower WCS benchmark oil prices and lower production, partially offset by lower non-energy operating expenses. During 2020, the Leismer Operating Netback was $3.02/bbl compared to $23.35/bbl in 2019, with the decline primarily resulting from unprecedented oil price volatility in the second and third quarters of 2020.

Total operating expenses were $12.72/bbl in the fourth quarter of 2020 and $11.56/bbl in 2020, compared to $14.96/bbl and $14.54/bbl in the comparable periods of 2019. Non-energy costs per bbl decreased relative to the prior year periods due to the completion of the disposal well project and several cost optimization initiatives in 2020. Energy operating costs per barrel in the fourth quarter of 2020 were higher relative to the prior year primarily due to higher gas prices offset by improvements in the projects Steam Oil Ratio (“SOR”).

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.

Hangingstone Operating Results

	Three months ended December 31, 2020	2019	Year ended December 31, 2020	2019
VOLUMES				
Bitumen production (bbl/d)	7,460	8,465	4,481	8,493
Bitumen sales (bbl/d)	7,372	6,587	4,837	8,076
Heavy oil (blended bitumen) sales (bbl/d)	10,698	9,466	7,113	11,691

($ Thousands, unless otherwise noted)	Three months ended December 31, 2020	2019	Year ended December 31, 2020	2019
Heavy oil (blended bitumen) sales	$ 40,443	$ 42,104	$ 83,017	$ 232,504
Cost of diluent	(18,867)	(20,390)	(56,603)	(102,881)
Total bitumen sales	21,576	21,714	26,414	129,623
Royalties	(128)	(509)	(315)	(3,123)
Operating expenses - non-energy	(5,226)	(7,294)	(16,102)	(35,399)
Operating expenses - energy	(6,918)	(4,919)	(15,823)	(19,569)
Transportation and marketing	(9,492)	(8,102)	(24,511)	(37,605)
Hangingstone Operating Income (Loss)(1)	$ (188)	$ 890	$ (30,337)	$ 33,927
REALIZED PRICE				
Heavy oil (blended bitumen) sales ($/bbl)	$ 41.09	$ 48.35	$ 31.89	$ 54.49
Bitumen sales ($/bbl)	$ 31.81	$ 35.83	$ 14.92	$ 43.97
Royalties ($/bbl)	(0.19)	(0.84)	(0.18)	(1.06)
Operating expenses - non-energy ($/bbl)	(7.71)	(12.04)	(9.10)	(12.01)
Operating expenses - energy ($/bbl)	(10.20)	(8.12)	(8.94)	(6.64)
Transportation and marketing ($/bbl)	(14.00)	(13.37)	(13.85)	(12.76)
HANGINGSTONE OPERATING NETBACK(1) ($/bbl)	$ (0.29)	$ 1.46	$ (17.15)	$ 11.50

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

Due to the significant decline in oil prices combined with the economic uncertainty associated to the COVID-19 pandemic, Athabasca suspended the Hangingstone SAGD operation early in the second quarter of 2020. A planned facility turnaround was completed during the summer. Operations were restarted on September 1, 2020 and bitumen production has returned to pre-shut-in levels with current production of approximately 8,800 bbl/d in February 2021.

The Hangingstone Operating Netback was $(0.29)/bbl during the fourth quarter of 2020 compared to $1.46/bbl in the fourth quarter of 2019 primarily due to lower WCS benchmark oil prices and lower production. During 2020, the Hangingstone Operating Netback was $(17.15)/bbl compared to $11.50/bbl in 2019, decreasing primarily as a result of lower WCS benchmark oil prices and lower production.

Total operating expenses were $17.91/bbl in the fourth quarter of 2020 and $18.04/bbl in 2020, compared to $20.16/bbl and $18.65/bbl in the comparable periods of 2019. Non-energy costs per bbl decreased relative to the prior year periods due to several cost optimization initiatives in 2020. Energy operating costs per barrel increased relative to the prior year periods primarily due to higher gas prices and a higher SOR as the asset was ramping back up.

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.

Consolidated Thermal Oil Operating Results

	Three months ended December 31, 2020	2019	Year ended December 31, 2020	2019
VOLUMES				
Bitumen production (bbl/d)	24,839	27,761	22,745	26,058
Bitumen sales (bbl/d)	24,613	25,049	23,157	25,478
Heavy oil (blended bitumen) sales (bbl/d)	34,731	34,972	32,632	35,697

($ Thousands, unless otherwise noted)	Three months ended December 31, 2020	2019	Year ended December 31, 2020	2019
Heavy oil (blended bitumen) sales	$ 132,635	$ 156,197	$ 383,940	$ 708,117
Cost of diluent	(57,806)	(68,428)	(212,400)	(286,957)
Total bitumen sales	74,829	87,769	171,540	421,160
Royalties	(557)	(2,488)	(2,150)	(11,545)
Operating expenses - non-energy	(16,921)	(23,566)	(62,329)	(99,138)
Operating expenses - energy	(15,407)	(14,057)	(47,145)	(48,229)
Transportation and marketing	(21,198)	(19,000)	(70,056)	(80,052)
Thermal Oil Operating Income (Loss)(1)	$ 20,746	$ 28,658	$ (10,140)	$ 182,196
REALIZED PRICE				
Heavy oil (blended bitumen) sales ($/bbl)	$ 41.51	$ 48.55	$ 32.15	$ 54.35
Bitumen sales ($/bbl)	$ 33.05	$ 38.09	$ 20.24	$ 45.29
Royalties ($/bbl)	(0.25)	(1.08)	(0.25)	(1.24)
Operating expenses - non-energy ($/bbl)	(7.47)	(10.23)	(7.35)	(10.66)
Operating expenses - energy ($/bbl)	(6.80)	(6.10)	(5.56)	(5.19)
Transportation and marketing ($/bbl)	(9.36)	(8.24)	(8.27)	(8.61)
THERMAL OIL OPERATING NETBACK(1) ($/bbl)	$ 9.17	$ 12.44	$ (1.19)	$ 19.59

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

Thermal Oil Segment Income (Loss)

($ Thousands)	Three months ended December 31, 2020	2019	Year ended December 31, 2020	2019
Thermal Oil Operating Income (Loss)(1)	$ 20,746	$ 28,658	$ (10,140)	$ 182,196
Impairment loss	—	—	(207,884)	—
Depletion and depreciation	(11,117)	(14,605)	(46,912)	(57,532)
Gain (loss) on sale of assets	58	105	21,289	223,858
Exploration and non-producing asset expenses	(514)	(384)	(22,410)	(2,330)
THERMAL OIL SEGMENT INCOME (LOSS)	$ 9,173	$ 13,774	$ (266,057)	$ 346,192

(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. As a result of the impairment, depletion and depreciation decreased in 2020 compared to 2019. Non-producing asset expenses relate to Hangingstone costs incurred during the suspension from April 2020 up to September 1, 2020 when Hangingstone recommenced production. These costs are mainly comprised of committed transportation and utilities distribution costs excluding costs directly associated with the suspension which are recognized in restructuring expenses.

During the second quarter of 2020, Athabasca recorded a gain of $21.0 million on the Burgess Royalty Transaction related to cash proceeds received in relation to the Company’s fully impaired assets, including Hangingstone, Birch, Dover West and Grosmont. The remaining cash proceeds of $49.0 million were allocated to Leismer and Corner, and reduced the carrying value of those assets.

During the first quarter of 2019, Athabasca recorded a gain of $222.8 million on the sale of its Leismer pipelines and Cheecham storage terminal.

Thermal Oil Capital Expenditures

($ Thousands)	Three months ended December 31, 2020	2019	Year ended December 31, 2020	2019
Leismer Project	$ 14,754	$ 19,382	$ 41,897	$ 79,430
Hangingstone Project	2,108	3,774	7,572	9,592
Other Thermal Oil exploration	53	73	318	321
TOTAL THERMAL OIL CAPITAL EXPENDITURES(1)	$ 16,915	$ 23,229	$ 49,787	$ 89,343

(1) For the three months and year ended December 31, 2020, capital expenditures include $0.7 million and $3.1 million of capitalized staff costs (three months and year ended December 31, 2019 - $1.2 million and $4.8 million).

Thermal Oil capital expenditures for the fourth quarter of 2020 of $16.9 million were primarily related to routine pump replacements and progressing drilling initiatives for 2021 to sustain production at Leismer. The 2021 drilling at Leismer will include one additional well pair at Pad L7 and two infill wells at Pad L6. Capital expenditures in 2020 of $49.8 million also included the completion of the Leismer water disposal project, the drilling of four observation wells for Pad 8, and Pad 8 readiness activities such as long-lead items, lease site and road construction, and pipeline access.

CORPORATE REVIEW

Liquidity and Capital Resources

Funding

Balance sheet strength and flexibility is a key priority for Athabasca. The Company's objective in managing capital is to ensure it has sufficient funding to sustain its core operating properties and a resilient balance sheet with sufficient liquidity. The Company expects to achieve this objective through prudent capital spending, an active commodity risk management program and by maintaining sufficient liquidity to manage periods of volatility within its cash, cash equivalent and short-term investment accounts, as well as through available credit facilities.

As at December 31, 2020, Athabasca had liquidity of $165.5 million, representing its unrestricted cash and cash equivalents balance and unutilized portion of the unsecured letter of credit facility.

In 2021, 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. Beyond 2021, depending on the Company's level of capital spend and the commodity price environment, the Company will need to re-finance its 2022 Notes and may require additional funding which could include debt, equity, joint ventures, asset sales or other external financing. The availability of any additional future funding will depend on, among other things, the current commodity price environment, operating performance, the Company's credit rating and its ability to access the equity and debt capital markets.

Indebtedness

As at ($ Thousands)	December 31, 2020	December 31, 2019
2022 Notes(1)	$ 572,940	$ 583,425
Debt issuance costs	(47,081)	(47,081)
Amortization of debt issuance costs	33,639	23,343
TOTAL LONG-TERM DEBT	$ 559,498	$ 559,687

(1) As at December 31, 2020, the US dollar denominated 2022 Notes were translated into Canadian dollars at the period end exchange rate of US$1.00 = C$1.2732 (2019 – C$1.2965).

Athabasca had the following debt instruments and credit facilities in place as at December 31, 2020:

2022 Notes

On February 24, 2017, Athabasca issued US$450.0 million of Senior Secured Second Lien Notes (the "2022 Notes"). The 2022 Notes bear interest at a rate of 9.875% per annum, payable semi-annually, and mature on February 24, 2022.

Athabasca may redeem the 2022 Notes at 100% of the principal from February 24, 2021 to maturity.

Credit Facility

In the fourth quarter of 2020, the Company's banking syndicate renewed the reserve-based credit facility (the "Credit Facility") until May 31, 2021, at which time it may be extended at the lender's option. The credit facility is $38.0 million and reflects the outstanding letters of credit for transportation commitments. The Credit Facility is collateralized by the Company's restricted cash balances. If the revolving period is not extended any outstanding letters of credit would be cancelled. The borrowing base is determined based on the lender's evaluation of the Company's reserves and their commodity price outlook at the time of each renewal.

As at December 31, 2020, the Company had no amounts drawn and had $38.0 million letters of credit issued under the Credit Facility which bear interest at 0.7%. As at December 31, 2019, the Company had no amounts drawn and had $39.4 million of letters of credit issued under the Credit Facility.

Under the terms of the Credit Facility, Athabasca is required to contribute cash to a cash-collateral account equivalent to 101% of the value of all letters of credit issued under the Credit Facility. As at December 31, 2020, $38.5 million of restricted cash was held in the cash-collateral account (December 31, 2019 - $nil). The Credit Facility is secured by a first priority security interest on all present and after acquired property of the Company and is senior in priority to the 2022 Notes. The Credit Facility contains certain covenants that limit the Company's ability to, among other things, incur additional indebtedness, create or permit liens to exist, make certain restricted payments, and dispose of or transfer assets. The Credit Facility also contains certain maximum hedging limitations. The Company is in compliance with all covenants.

Cash-Collateralized Letter of Credit Facility

Athabasca maintains 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. The facility is available on a demand basis and letters of credit issued under the Letter of Credit Facility incur an issuance fee of 0.25%. As at December 31, 2020, Athabasca had $96.0 million (December 31, 2019 - $109.5 million) in letters of credit issued under the Letter of Credit Facility.

Under the terms of the Letter of Credit Facility, Athabasca is required to contribute cash to a cash-collateral account equivalent to 101% of the value of all letters of credit issued under the facility. As at December 31, 2020, $97.1 million of restricted cash was held in the cash-collateral account (December 31, 2019 - $110.6 million).

Unsecured Letter of Credit Facility

Athabasca increased its unsecured letter of credit facility (the "Unsecured Letter of Credit Facility") to $40.0 million in the fourth quarter of 2020 (December 31, 2019 - $30.0 million). The Unsecured Letter of Credit Facility is held with a Canadian bank and is supported by a performance security guarantee from Export Development Canada. The facility is available on a demand basis and letters of credit issued under this facility incur an issuance and performance guarantee fee of 3.5%. As at December 31, 2020, the Company had $39.7 million of letters of credit issued under the Unsecured Letter of Credit Facility (December 31, 2019 - $24.8 million).

Financing and Interest

($ Thousands)	Three months ended December 31, 2020	2019	Year ended December 31, 2020	2019
Financing and interest expense on indebtedness	$ 14,876	$ 15,396	$ 61,709	$ 61,118
Amortization of debt issuance costs	2,706	2,527	10,700	9,387
Accretion of provisions	3,284	2,991	12,513	11,608
Interest expense on lease liability	345	409	1,480	1,726
TOTAL FINANCING AND INTEREST	$ 21,211	$ 21,323	$ 86,402	$ 83,839

During the three months and year ended December 31, 2020 and 2019, financing and interest expenses were primarily attributable to the Company's 2022 Notes.

Foreign Exchange Gain (Loss), Net

($ Thousands)	Three months ended December 31, 2020	2019	Year ended December 31, 2020	2019
Unrealized foreign exchange gain (loss)	$ 22,640	$ 12,230	$ 4,454	$ 30,320
Realized foreign exchange gain (loss)	47	(1,029)	2,270	(321)
FOREIGN EXCHANGE GAIN (LOSS), NET	$ 22,687	$ 11,201	$ 6,724	$ 29,999

Athabasca is exposed to foreign currency risk primarily on the principal and interest components of its US dollar denominated 2022 Notes partially offset by its US dollar cash, restricted cash and deposits. The net foreign exchange gains (losses) recognized were primarily due to unrealized gains (losses) on the note principal as the value of the Canadian dollar fluctuates relative to the US dollar.

Risk Management Contracts

Under the Company's commodity risk management program, Athabasca may utilize financial and/or physical delivery contracts to fix the commodity price associated with a portion of its future production in order to manage its exposure to fluctuations in commodity prices.

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

Financial commodity risk management contracts

As at December 31, 2020, 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 2021	11,000 bbl/d	$ 50.80 - 58.10	$ 39.90 - 45.63
WTI three way collar	January - June 2021	7,000 bbl/d	$ 50.93|57.29|72.64	$ 40.00|45.00|57.05
WTI sold call options(2)	April - June 2021	8,900 bbl/d	$ 70.03	$ 55.00
WTI sold call options(2)	July - December 2021	15,900 bbl/d	$ 71.18	$ 55.90
WTI/WCS differential swaps	January - March 2021	18,000 bbl/d	$ (18.38)	$ (14.44)
WTI/WCS differential swaps	April - September 2021	7,500 bbl/d	$ (15.26)	$ (11.98)
Purchase contracts			*C$/GJ*	*US$/GJ*
AECO fixed price swaps	January - December 2021	10,000 GJ/d	$ 2.73	$ 2.14

(1) The implied C$ or US$ Average Price/bbl, as applicable, was calculated using the December 31, 2020 exchange rate of US$1.00 = C$1.2732.
(2) These WTI call options were sold to a counterparty to enhance the October 2020 to March 2021 WTI collars at the price detailed in the above table.

The following table summarizes the Company's net gain (loss) on commodity risk management contracts for the three months and year ended December 31, 2020 and 2019:

($ Thousands)	Three months ended December 31, 2020	2019	Year ended December 31, 2020	2019
Unrealized gain (loss) on commodity risk mgmt. contracts	$ 4,886	$ (3,634)	$ 13,329	$ (2,437)
Realized gain (loss) on commodity risk mgmt. contracts	(9,353)	(2,064)	29,149	(43,981)
GAIN (LOSS) ON COMMODITY RISK MGMT. CONTRACTS, NET	$ (4,467)	$ (5,698)	$ 42,478	$ (46,418)

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

As at December 31, 2020	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	$ (6,266)	$ 5,996	$ 3,773	$ (3,773)

Additional financial commodity risk management activity related to 2021 has taken place subsequent to December 31, 2020, as noted in the table below:

Instrument	Period	Volume	C$ Average Price/bbl(1)	US$ Average Price/bbl(1)
Sales contracts				
WTI/WCS differential swaps	July - September 2021	5,000 bbl/d	$ 15.60	$ 12.25
WTI/WCS differential swaps	October - December 2021	5,000 bbl/d	$ 16.49	$ 12.95

(1) The implied C$ or US$ Average Price/bbl, as applicable, was calculated using the December 31, 2020 exchange rate of US$1.00 = C$1.2732.

Commitments and Contingencies

The following table summarizes Athabasca’s estimated future unrecognized minimum commitments as at December 31, 2020 for the following five years and thereafter:

($ Thousands)	2021	2022	2023	2024	2025	Thereafter	Total
Transportation and processing(1)	$ 121,491	$ 127,145	$ 181,986	$ 191,727	$ 188,904	$2,974,032	$3,785,285
Interest expense on long-term debt(1)	36,776	28,289	—	—	—	—	65,065
Purchase commitments	17,544	376	—	—	—	—	17,920
TOTAL COMMITMENTS	$ 175,811	$ 155,810	$ 181,986	$ 191,727	$ 188,904	$2,974,032	$3,868,270

(1) Commitments which are denominated in US dollars were translated into Canadian dollars at the December 31, 2020 exchange rate of US$1.00 = C$1.2732.

In April 2020, Athabasca reassigned 15,000 bbl/d of its Keystone XL pipeline transportation commitment to a third party and accordingly $849.5 million of total related transportation commitments were removed from the above disclosure. The Company retains 10,000 bbl/d of capacity commitments on Keystone XL.

As disclosed previously, during the third quarter of 2019 Athabasca participated in TC Energy’s (“TCE”) 50,000 bbl/d open season on the existing Keystone system with service from Hardisty to the US Gulf Coast. Athabasca entered into a 20 year firm service transportation agreement with TCE for 7,200 bbl/d of service that was anticipated to be made available in 2020. The ultimate in-service date remains uncertain. In consideration for the Keystone service, Athabasca concurrently entered into a development cost agreement in relation to the Keystone XL pipeline. This agreement provides for a US$48.4 million ($61.6 million) conditional payment, which is only payable if shipper agreements on the Keystone XL pipeline were terminated on or before January 31, 2020. The Keystone XL shipper agreements were subsequently extended to March 31, 2021. In connection with such agreements, Athabasca provided $82.4 million in financial assurances, consisting of a $31.9 million (US$25 million) cash deposit and $50.5 million of letters of credit which are secured by the Company’s restricted cash balances.

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, accounts receivables from petroleum and natural gas marketers and joint interest partners and risk management contract counterparties.

Athabasca’s cash, cash equivalents and restricted cash are held with five counterparties, all of which are large reputable financial institutions, and management concluded that credit risk associated with these 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, 2020. Athabasca's risk management contracts are held with a single counterparty, which is a large reputable financial institution, and management concluded that credit risk associated with these risk management contracts is low.

For the year ended December 31, 2020, the Company had sales to four customers which each ranged from 17% to 31% of total sales. Sales to such customers totaled $416 million, or 90%, of total 2020 sales.

Interest Rate Risk

The Company's exposure to interest rate fluctuations on interest earned on its floating rate cash, cash equivalents and restricted cash balance at December 31, 2020 of $300.8 million (December 31, 2019 - $365.0 million), from a 1.0% change in interest rates, would have an annualized impact of approximately $3.0 million (year ended December 31, 2019 - $3.7 million). The 2022 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, 2020	2019	Year ended December 31, 2020	2019
TOTAL GENERAL AND ADMINISTRATIVE	$ 5,305	$ 6,202	$ 19,431	$ 22,645
G&A per boe	$ 1.68	$ 1.85	$ 1.63	$ 1.71

During the three months and year ended December 31, 2020, Athabasca's G&A expenses and G&A per boe decreased compared to the same periods in the prior year, primarily due to reduced salaries and benefits.

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.

Stock Based Compensation

During the three months and year ended December 31, 2020, Athabasca's stock-based compensation was a $1.4 million and $2.8 million, respectively, compared to $1.0 million and $6.8 million in the respective prior year periods. The decrease in 2020 is primarily due to the lower share price in 2020 compared to 2019 resulting in the value of the overall compensation to be lower.

Gain (Loss) on Revaluation of Provisions and Other

($ Thousands)	Three months ended December 31, 2020	2019	Year ended December 31, 2020	2019
Contingent payment obligation	$ —	$ 339	$ 1,028	$ 3,442
Capital-carry receivable	—	744	138	2,420
Provision for pipeline project	(61,590)	—	(61,590)	—
Other	467	(1,393)	(648)	(1,402)
TOTAL GAIN (LOSS) ON REVALUATION OF PROVISIONS AND OTHER	$ (61,123)	$ (310)	$ (61,072)	$ 4,460

The gains on revaluation of the contingent payment obligation are primarily due to fluctuations in forecasted prices for WTI. See the commitments and contingencies section for an explanation on the provision for pipeline project.

Income Taxes

As at December 31, 2020, Athabasca did not recognize deductible temporary differences of $2.5 billion (December 31, 2019 - $2.0 billion) primarily consisting of approximately $1.8 billion (December 31, 2019 - $1.6 billion) in non-capital losses and $0.7 billion (December 31, 2019 - $0.4 billion) in CCA and resource pools in excess of capital assets. The Company has approximately $3.3 billion in tax pools, including approximately $2.4 billion in non-capital losses and exploration tax pools available for immediate deduction against future income. The non-capital losses begin to expire after 2025.

From time to time, Athabasca undergoes income tax audits in the normal course of business. The Company has received notice of reassessments from the Canada Revenue Agency ("CRA") and Alberta Finance. While the final outcome of such reassessments 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 reassessments. As such, the Company has not recognized any provision in its consolidated financial statements with respect to the reassessments and has posted a $12.6 million deposit with the CRA while objecting the reassessments.

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, 2020, there were 530.7 million common shares outstanding, an aggregate of 19.5 million restricted share units and performance share units outstanding, 7.0 million stock options outstanding, 7.0 million deferred shares units outstanding and 8.4 million units outstanding under a new "Phantom Share Unit" plan in 2020. The units granted under this new plan will generally vest evenly over three years, have no exercise price and automatically settle in cash on each vesting date at an amount equivalent to the share price at that date. Accordingly, the "Phantom Share Unit" plan is a cash-settled stock-based compensation plan. During 2020, Athabasca issued 7.2 million common shares in respect of the Company's equity-settled share-based compensation plans. There were no material changes in these balances between December 31, 2020 and March 3, 2021.

SUMMARY OF QUARTERLY RESULTS

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

	2020				2019			
($ Thousands, unless otherwise noted)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	42.66	40.93	27.85	46.17	56.96	56.45	59.82	54.90
WTI (C$/bbl)	55.58	54.50	38.59	62.03	75.19	74.56	80.11	72.97
Western Canadian Select (C$/bbl)	43.40	42.39	22.41	34.11	54.27	58.36	65.73	56.62
Edmonton Par (C$/bbl)	49.98	49.54	29.55	51.62	67.99	68.21	73.60	66.41
Edmonton Condensate (C5+) (C$/bbl)	55.05	49.78	29.95	60.39	69.22	68.03	74.46	66.60
AECO (C$/GJ)	2.50	2.12	1.89	1.93	2.35	0.87	0.98	2.49
Chicago Citygate (US$/MMBtu)	2.27	1.83	1.61	1.74	2.20	2.08	2.31	2.82
Foreign exchange (USD : CAD)	1.30	1.33	1.39	1.34	1.32	1.32	1.34	1.33
CONSOLIDATED								
Petroleum and natural gas production (boe/d)(1)	34,233	32,061	27,067	36,557	36,403	35,257	33,958	39,206
Realized price (net of cost of diluent) ($/boe)	33.56	33.62	9.03	15.47	38.61	43.63	50.69	42.25
Petroleum and natural gas sales ($)(2)	162,815	134,188	56,037	138,500	188,101	216,338	224,531	226,127
Operating Income (Loss) ($)(1)	30,935	42,812	6,166	1,098	42,881	64,614	67,122	58,602
Operating Netback ($/boe)(1)	9.89	14.67	2.37	0.33	13.84	19.10	22.19	16.77
Capital expenditures ($)	17,202	12,381	5,811	76,246	69,796	42,664	33,717	52,964
Capital Expenditures Net of Capital-Carry ($)(1)	17,202	12,381	5,811	53,506	46,259	35,304	26,888	31,756
LIGHT OIL DIVISION								
Petroleum and natural gas production (boe/d)(1)	9,394	11,830	9,466	8,242	8,642	10,023	10,210	11,712
Realized price ($/boe)	34.92	33.32	19.51	32.46	40.13	37.37	39.65	41.53
Petroleum and natural gas sales ($)(2)	30,180	36,267	16,806	24,347	31,904	34,462	36,836	43,778
Operating Income (Loss) ($)(1)	19,542	23,327	6,350	12,783	16,287	21,800	25,637	31,280
Operating Netback ($/boe)(1)	22.61	21.43	7.37	17.04	20.49	23.64	27.59	29.67
Capital expenditures ($)	117	1,917	1,089	58,527	46,473	21,501	11,858	29,855
Capital Expenditures Net of Capital-Carry ($)(1)	117	1,917	1,089	35,787	22,936	14,141	5,029	8,647
THERMAL OIL DIVISION								
Bitumen production (bbl/d)	24,839	20,231	17,601	28,315	27,761	25,234	23,748	27,494
Bitumen sales volumes (bbl/d)	24,613	19,895	19,045	29,095	25,049	26,744	23,028	27,100
Realized bitumen price ($/bbl)	33.05	33.80	3.83	10.66	38.09	45.97	55.58	42.56
Heavy Oil (blended bitumen) sales ($)	132,635	97,921	39,231	114,153	156,197	181,876	187,695	182,349
Operating Income (Loss) ($)(1)	20,746	26,844	(24,619)	(33,111)	28,658	51,888	56,522	45,128
Operating Netback ($/bbl)(1)	9.17	14.66	(14.21)	(12.50)	12.44	21.09	26.97	18.50
Capital expenditures ($)	16,915	10,454	4,722	17,696	23,229	21,146	21,859	23,109
OPERATING RESULTS								
Cash flow from operating activities ($)	16,079	(4,782)	(31,186)	(3,021)	32,975	16,741	61,488	(18,572)
Adjusted Funds Flow ($)(1)	10,753	14,617	(16,214)	(27,883)	21,478	43,906	47,757	41,619
Net income (loss) ($)	(56,891)	(18,818)	(65,335)	(516,481)	(8,757)	(8,265)	57,091	206,796
Net income (loss) per share - basic ($)	(0.11)	(0.04)	(0.12)	(0.99)	(0.02)	(0.02)	0.11	0.40
BALANCE SHEET ITEMS								
Cash and cash equivalents ($)	165,201	151,730	167,442	199,517	254,389	255,433	292,851	272,240
Restricted cash ($)	135,624	150,887	152,125	110,634	110,609	110,629	111,092	106,385
Capital-carry receivable (discounted) ($)(3)	—	—	—	—	22,602	45,395	52,570	58,861
Total assets ($)	1,425,984	1,425,343	1,468,248	1,599,860	2,093,465	2,081,910	2,068,778	2,066,858
Long-term debt ($)(3)	559,498	584,108	594,488	617,123	559,687	569,750	560,538	570,411
Shareholders' equity ($)	567,025	622,771	640,515	705,055	1,220,062	1,227,214	1,232,912	1,172,954

(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 2020, 2019 and 2018:

($ Thousands, unless otherwise noted)	December 31, 2020	December 31, 2019	December 31, 2018
Petroleum and natural gas production (boe/d)[1]	32,483	36,196	39,203
Petroleum and natural gas sales	$ 464,648	$ 836,933	$ 809,637
Net income (loss) and comprehensive income (loss)	$ (657,525)	$ 246,865	$ (569,657)
per share (basic and diluted)	$ (1.24)	$ 0.47	$ (1.11)
Cash flow from operating activities	$ (22,910)	$ 92,632	$ 83,844
per share (basic)	$ (0.04)	$ 0.18	$ 0.16
Adjusted Funds Flow[1]	$ (18,727)	$ 154,760	$ 6,175
per share (basic)	$ (0.04)	$ 0.30	$ 0.01
Capital expenditures	$ 111,640	$ 199,141	$ 276,328
Capital Expenditures Net of Capital-Carry[1]	$ 88,900	$ 140,207	$ 193,980
Total assets	$ 1,425,984	$ 2,093,465	$ 1,825,638
Face value of long-term debt[2]	$ 572,940	$ 583,425	$ 614,070
Weighted average shares outstanding (basic)	528,837,646	521,316,320	514,151,731
Weighted average shares outstanding (diluted)	528,837,646	526,290,689	514,151,731

(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 2022 Notes is US$450 million. The 2022 Notes were translated into Canadian dollars at the December 31, 2020 exchange rate of US$1.00 = C$1.2732.

ACCOUNTING POLICIES AND ESTIMATES

During the three months and year ended December 31, 2020, there were no changes to Athabasca's accounting policies or use of estimates in the preparation of the consolidated financial statements and the notes thereto. A summary of the significant accounting policies used by Athabasca can be found in Note 3 of the December 31, 2020 audited consolidated financial statements.

In March 2020, the COVID-19 outbreak was declared a pandemic by the World Health Organization. Global commodity prices declined significantly due to a reduction in oil demand as countries around the world, including Canada, enacted emergency measures to combat the spread of the virus. Throughout the second half of 2020, economies have started to reopen along with positive developments on the vaccine front leading to a strong recovery in oil prices. The significant impacts of the COVID-19 pandemic on Athabasca include:

- declines in revenue and cash flows as a result of the collapse in commodity prices and resulting in production curtailments;
- reduced capital program for 2020 which did not impact production capability levels in 2020 however continued reduced capital programs could have negative effects on future production levels;
- declines in commodity prices, revenue and cash flows leading to impairment charges (Note 13) and increased risk of onerous contracts related to committed fixed cost contracts;
- increased risk of non-payment of accounts receivable and customer defaults; and
- non-producing asset expenses and restructuring charges related to the suspension of the Hangingstone operations (Notes 21 and 22).

Estimates and judgements made by management in the preparation of the consolidated financial statements are subject to a higher degree of measurement uncertainty during this volatile period.

For the year ended December 31, 2020, Athabasca's significant estimates and judgment are as follows:

Significant Accounting Estimates and Judgments

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

Judgment was applied in determining the recording of the Provision for the Keystone XL pipeline project (Note 15) and the current/non-current classification.

Included in the carrying value of property, plant and equipment ("PP&E") are accumulated depletion, depreciation and impairment charges 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 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 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 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, 2020 and as at December 31, 2019, Athabasca did not recognize deductible temporary differences in respect of income tax assets (Note 25).

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 2022 Notes. 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 and forfeiture rates which are based on management's assumptions and estimates.

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 Financial Measures and production disclosure

The "Adjusted Funds Flow", "Light Oil Operating Income (Loss)", "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" and "Consolidated Capital Expenditures Net of Capital-Carry" 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 measures. 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 following table reconciles cash flow from operating activities in the consolidated financial statements for the three months and year ended December 31, 2020 and 2019 to Adjusted Funds Flow:

($ Thousands)	Three months ended December 31, 2020	2019	Year ended December 31, 2020	2019
Cash flow from operating activities	$ 16,079	$ 32,975	$ (22,910)	$ 92,632
Restructuring expenses	—	—	5,703	—
Changes in non-cash working capital	(5,614)	(11,886)	(11,670)	58,453
Settlement of provisions	288	389	10,150	3,675
ADJUSTED FUNDS FLOW	$ 10,753	$ 21,478	$ (18,727)	$ 154,760

Adjusted Funds Flow is not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS. Adjusted Funds Flow is calculated by adjusting for changes in non-cash working capital, restructuring expenses and settlement of provisions from cash flow from operating activities. The Adjusted Funds Flow measure allows 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 calculated as Adjusted Funds Flow divided by the applicable number of weighted average shares outstanding.

The Light Oil Operating Income (Loss) measure in this MD&A is calculated by subtracting royalties, operating expenses and transportation & marketing expenses from petroleum and natural gas sales. The Light Oil Operating Netback measure is calculated by dividing the Light Oil Operating Income (Loss) by the Light Oil production and is presented on a per boe basis. The Light Oil Operating Income (Loss) and the Light Oil Operating Netback measures allow management and others to evaluate the production results from the Company's Light Oil assets. The table on page 9 reconciles Light Oil Operating Income (Loss) to *Note 19 - Segmented Information* in the consolidated financial statements for the three months and year ended December 31, 2020.

The Operating Income (Loss) measure in this MD&A with respect to the Leismer Project and Hangingstone Project is calculated by subtracting the cost of diluent blending, royalties, operating expenses and transportation & marketing expenses from heavy oil (i.e. blended bitumen) sales. The Thermal Oil Operating Netback measure is calculated by dividing the respective projects Operating Income (Loss) by its respective bitumen sales volumes and is presented on a per barrel basis. The Thermal Oil Operating Income (Loss) and the Thermal Oil Operating Netback measures allow management and others to evaluate the production results from the Company's Thermal Oil assets. The table on page 13 reconciles Thermal Oil Operating Income (Loss) to *Note 19 - Segmented Information* in the consolidated financial statements for the three months and year ended December 31, 2020.

The Consolidated Operating Income (Loss) measure in this MD&A is calculated by adding or subtracting realized gains (losses) on commodity risk management contracts, royalties, the cost of diluent blending, operating expenses and transportation & marketing expenses from petroleum and natural gas sales. The Consolidated Operating Netback measure is calculated by dividing Consolidated Operating Income (Loss) by the total sales volumes and is presented on a per boe basis. The Consolidated Operating Income (Loss) and the Consolidated Operating Netback 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) to *Note 19 - Segmented Information* in the consolidated financial statements for the three months and year ended December 31, 2020.

The Consolidated Capital Expenditures Net of Capital-Carry and Light Oil Capital Expenditures Net of Capital-Carry measures in this MD&A are calculated in the tables on pages 7 and 9. These measures allow management and others to evaluate the true net cash outflow related to Athabasca's capital expenditures.

Production volumes details

Production		2020 Q4	2020 Q3	2020 Q2	2020 Q1	2020 Annual	2019 Q4	2019 Q3	2019 Q2	2019 Q1	2019 Annual
Greater Placid:											
Condensate NGLs	bbl/d	1,841	2,612	1,916	1,480	1,964	1,457	1,734	2,150	2,711	2,009
Other NGLs	bbl/d	523	632	389	351	474	493	439	524	556	503
Natural gas(1)	mcf/d	17,900	19,668	14,221	12,939	16,197	15,723	17,538	20,441	22,424	19,009
Total Greater Placid	**boe/d**	**5,347**	**6,522**	**4,675**	**3,988**	**5,138**	**4,571**	**5,096**	**6,081**	**7,004**	**5,680**
Greater Kaybob:											
Oil(2)	bbl/d	2,845	3,685	3,226	2,708	3,117	2,336	2,985	2,186	2,480	2,498
Other NGLs	bbl/d	264	332	291	359	311	406	372	349	536	415
Natural gas(1)	mcf/d	5,629	7,746	7,642	7,123	7,032	7,972	9,421	9,564	10,152	9,272
Total Greater Kaybob	**boe/d**	**4,047**	**5,308**	**4,791**	**4,254**	**4,600**	**4,071**	**4,927**	**4,129**	**4,708**	**4,458**
Light Oil:											
Oil(2)	bbl/d	2,845	3,685	3,226	2,708	3,117	2,336	2,985	2,186	2,480	2,498
Condensate NGLs	bbl/d	1,841	2,612	1,916	1,480	1,964	1,457	1,734	2,150	2,711	2,009
Oil and condensate NGLs	bbl/d	4,686	6,297	5,142	4,188	5,081	3,793	4,719	4,336	5,191	4,507
Other NGLs	bbl/d	787	964	680	710	785	899	811	873	1,092	918
Natural gas(1)	mcf/d	23,529	27,414	21,863	20,062	23,229	23,695	26,959	30,005	32,576	28,281
Total Light Oil division	**boe/d**	**9,394**	**11,830**	**9,466**	**8,242**	**9,738**	**8,642**	**10,023**	**10,210**	**11,712**	**10,138**
Total Thermal Oil division bitumen	**bbl/d**	**24,839**	**20,231**	**17,601**	**28,315**	**22,745**	**27,761**	**25,234**	**23,748**	**27,494**	**26,058**
Total Company production	**boe/d**	**34,233**	**32,061**	**27,067**	**36,557**	**32,483**	**36,403**	**35,257**	**33,958**	**39,206**	**36,196**

(1) Comprised of 97% or greater of shale gas, with the remaining being conventional natural gas

(2) Comprised of 98% 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 31,000 - 33,000 boe/d for 2021. Athabasca expects that approximately 77% of that production will be comprised of bitumen, 10% shale gas, 7% tight oil, 4% condensate natural gas liquids and 2% other natural gas liquids.

Liquids:		2020 Q4	2020 Q3	2020 Q2	2020 Q1	2020 Annual	2019 Q4	2019 Q3	2019 Q2	2019 Q1	2019 Annual
Greater Placid:											
Condensate NGLs	bbl/d	1,841	2,612	1,916	1,480	1,964	1,457	1,734	2,150	2,711	2,009
Other NGLs	bbl/d	523	632	389	351	474	493	439	524	556	503
Total Greater Placid Liquids	bbl/d	2,364	3,244	2,305	1,831	2,438	1,950	2,173	2,674	3,267	2,512
as % of Greater Placid prod.		44%	50%	49%	46%	47%	43%	43%	44%	47%	44%
Greater Kaybob:											
Oil	bbl/d	2,845	3,685	3,226	2,708	3,117	2,336	2,985	2,186	2,480	2,498
Other NGLs	bbl/d	264	332	291	359	311	406	372	349	536	415
Total Greater Kaybob Liquids	bbl/d	3,109	4,017	3,517	3,067	3,428	2,742	3,357	2,535	3,016	2,913
as % of Greater Kaybob prod.		77%	76%	73%	72%	75%	67%	68%	61%	64%	65%
Total Light Oil:											
Oil and condensate NGLs	bbl/d	4,686	6,297	5,142	4,188	5,081	3,793	4,719	4,336	5,191	4,507
Other NGLs	bbl/d	787	964	680	710	785	899	811	873	1,092	918
Total Light Oil division Liquids	bbl/d	5,473	7,261	5,822	4,898	5,866	4,692	5,530	5,209	6,283	5,425
as % of Light Oil production		58%	61%	62%	59%	60%	54%	55%	51%	54%	54%
Total Company:											
Total Light Oil division Liquids	bbl/d	5,473	7,261	5,822	4,898	5,866	4,692	5,530	5,209	6,283	5,425
Total Thermal Oil division bitumen	bbl/d	24,839	20,231	17,601	28,315	22,745	27,761	25,234	23,748	27,494	26,058
Total Company Liquids	bbl/d	30,312	27,492	23,423	33,213	28,611	32,453	30,764	28,957	33,777	31,483
as % of Company production		89%	86%	87%	91%	88%	89%	87%	85%	86%	87%

Comparative Figures

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

Disclosure Control and Procedures

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, 2020, 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, 2020, 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, 2020.

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;
- 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;
- 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 Credit Facility, the Letter of Credit Facility, the Unsecured Letter of Credit Facility and the 2022 Notes;
- 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;
- 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; drilling plans at Leismer; the Company's anticipated sources of funding for 2021 and beyond; the Company's estimated future minimum commitments; the future allocation of capital; 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, 2020 (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; Athabasca's cash flow break-even commodity price; 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; continued impact of the COVID-19 pandemic; ability to finance capital requirements; climate change and carbon pricing risk; regulatory environment and changes in applicable law; gathering and processing facilities, pipeline systems and rail; statutes and regulations regarding the environment; political uncertainty; state of capital markets; anticipated benefits of acquisitions and dispositions; abandonment and reclamation costs; changing demand for oil and natural gas products; royalty regimes; foreign exchange rates and interest rates; reserves; hedging; operational dependence; operating costs; project risks; 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; 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, 2020. 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 7 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 7 of this MD&A include: 63 proved undeveloped locations and 35 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, 2020 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, 2020, 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