Management’s Discussion and Analysis

Q3 2021

ATHABASCA OIL CORPORATION

This Management’s Discussion and Analysis of the financial condition and results of operations (“MD&A”) of Athabasca Oil Corporation (“Athabasca” or the “Company”) is dated November 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 (Oil Sands, Montney, Duvernay). The Company's strategy is guided by:

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

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

THIRD QUARTER 2021 HIGHLGHTS

Corporate

- Production of 34,255 boe/d (90% Liquids(1)).
- Record Operating Income(1) of $120.6 million ($92.7 million Operating Income Net of Realized Hedging(1)).
- Record Adjusted Funds Flow(1) of $72.2 million (cash flow from operating activities $75.7 million).
- Record Free Cash Flow(1) of $56.6 million.
- $274.0 million of unrestricted cash as at September 30, 2021.
- Subsequent to the quarter the Company completed the refinancing of its 2022 Second Lien Notes through the issuance of US$350 million of New Second Lien Notes maturing in 2026 and a new $110 million syndicated reserve based credit facility.

Thermal Oil Division

- Production of 26,729 bbl/d.
- Record Operating Income(1) of $94.8 million.
- Record Operating Netbacks(1) of $35.71/bbl ($37.09/bbl at Leismer and $32.92/bbl at Hangingstone) were supported by strong commodity prices and cost optimization initiatives.
- Capital expenditures of $15.2 million were focused on sustaining projects at Leismer. Activity included completing the Pad 8 pipeline and surface facilities. Pad 8 commenced steaming in October with first production expected in early 2022.

Light Oil Division

- Production of 7,526 boe/d (55% Liquids(1)).
- Operating Income(1) of $25.8 million and top tier industry Operating Netback(1) of $37.25/boe.
- Field activity focused on maintaining low operating cost structure with no drilling activity over this past quarter.

(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 September 30, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
CONSOLIDATED				
Petroleum and natural gas production (boe/d)(1)	34,255	32,061	34,439	31,896
Operating Income (Loss)(1)	$ 120,581	$ 50,171	$ 279,705	$ 11,574
Operating Income (Loss) Net of Realized Hedging(1)(2)	$ 92,742	$ 42,812	$ 212,929	$ 50,076
Operating Netback ($/boe)(1)	$ 36.02	$ 17.19	$ 29.54	$ 1.29
Operating Netback Net of Realized Hedging ($/boe)(1)(2)	$ 27.70	$ 14.67	$ 22.49	$ 5.61
Capital expenditures	$ 15,608	$ 12,381	$ 73,790	$ 94,438
Capital Expenditures Net of Capital-Carry(1)	$ 15,608	$ 12,381	$ 73,790	$ 71,698
Free Cash Flow(1)	$ 56,625	$ 2,236	$ 67,632	$ (101,178)
THERMAL OIL DIVISION				
Bitumen production (bbl/d)	26,729	20,231	26,374	22,043
Operating Income (Loss)(1)	$ 94,796	$ 26,844	$ 204,532	$ (30,886)
Operating Netback ($/bbl)(1)	$ 35.71	$ 14.66	$ 28.16	$ (4.98)
Capital expenditures	$ 15,228	$ 10,454	$ 69,630	$ 32,872
LIGHT OIL DIVISION				
Petroleum and natural gas production (boe/d)(1)	7,526	11,830	8,065	9,853
Percentage Liquids (%)(1)	55%	62%	56%	61%
Operating Income (Loss)(1)	$ 25,785	$ 23,327	$ 75,173	$ 42,460
Operating Netback ($/boe)(1)	$ 37.25	$ 21.43	$ 34.15	$ 15.73
Capital expenditures	$ 128	$ 1,917	$ 1,640	$ 61,534
Capital Expenditures Net of Capital-Carry(1)	$ 128	$ 1,917	$ 1,640	$ 38,794
CASH FLOW AND FUNDS FLOW				
Cash flow from operating activities	$ 75,743	$ (4,782)	$ 113,064	$ (38,989)
per share - basic	$ 0.14	$ (0.01)	$ 0.21	$ (0.07)
Adjusted Funds Flow(1)	$ 72,233	$ 14,617	$ 141,422	$ (29,480)
per share - basic	$ 0.14	$ 0.03	$ 0.27	$ (0.06)
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)				
Net income (loss) and comprehensive income (loss)	$ 104,951	$ (18,818)	$ 73,535	$ (600,634)
per share - basic	$ 0.20	$ (0.04)	$ 0.14	$ (1.14)
per share - diluted	$ 0.19	$ (0.04)	$ 0.14	$ (1.14)
COMMON SHARES OUTSTANDING				
Weighted average shares outstanding - basic	530,675,391	530,675,391	530,675,391	528,220,593
Weighted average shares outstanding - diluted	547,618,860	530,675,391	544,597,372	528,220,593

As at ($ Thousands)	September 30, 2021	December 31, 2020
LIQUIDITY AND BALANCE SHEET		
Cash and cash equivalents	$ 273,989	$ 165,201
Restricted cash	$ 46,107	$ 135,624
Available credit facilities(3)	$ 3,568	$ 348
Face value of long-term debt, including current portion(4)	$ 573,345	$ 572,940

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures and production disclosure.
(2) Includes realized commodity risk management loss of $27.8 million and $66.8 million for the three and nine months ended September 30, 2021 (three and nine months ended September 30, 2020 - $7.4 million loss and $38.5 million gain).
(3) Includes available credit under Athabasca's Credit Facility and Unsecured Letter of Credit Facility (see pages 13 and 14).
(4) The face value of the 2022 Notes is US$450 million. The 2022 Notes were translated into Canadian dollars at the September 30, 2021 exchange rate of US$1.00 = C$1.2741 (December 31, 2020 – C$1.2732).

BUSINESS ENVIRONMENT AND THE RECOVERY FROM COVID-19

Benchmark prices

(Average)	Three months ended September 30, 2021	2020	Change	Nine months ended September 30, 2021	2020	Change
Crude oil:						
West Texas Intermediate (WTI) (US$/bbl)[1]	$ 70.56	$ 40.93	72 %	$ 64.82	$ 38.32	69 %
West Texas Intermediate (WTI) (C$/bbl)[1]	$ 88.91	$ 54.50	63 %	$ 81.10	$ 51.85	56 %
Western Canadian Select (WCS) (C$/bbl)[2]	$ 71.77	$ 42.39	69 %	$ 65.37	$ 32.97	98 %
Edmonton Par (C$/bbl)[3]	$ 83.70	$ 49.54	69 %	$ 75.74	$ 43.57	74 %
Edmonton Condensate (C5+) (C$/bbl)[4]	$ 86.78	$ 49.78	74 %	$ 80.23	$ 46.71	72 %
WCS Differential:						
to WTI (US$/bbl)	$ (13.58)	$ (9.09)	49 %	$ (12.51)	$ (13.69)	(9) %
to WTI (C$/bbl)	$ (17.14)	$ (12.11)	42 %	$ (15.73)	$ (18.88)	(17) %
Edmonton Par Differential:						
to WTI (US$/bbl)	$ (4.08)	$ (3.51)	16 %	$ (4.14)	$ (5.74)	(28) %
to WTI (C$/bbl)	$ (5.21)	$ (4.96)	5 %	$ (5.36)	$ (8.28)	(35) %
Natural gas:						
AECO (C$/GJ)[5][6]	$ 3.41	$ 2.12	61 %	$ 3.11	$ 1.98	57 %
Chicago Citygate (US$/MMBtu)[6]	$ 4.08	$ 1.83	123 %	$ 4.44	$ 1.73	157 %
Foreign exchange:						
USD : CAD	1.2601	1.3316	(5) %	1.2511	1.3532	(8) %

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.

Commodity prices continue to strengthen as the world has emerged from the COVID-19 pandemic and the recovery in oil demand outpaces the growth in supply. Global oil demand is set to exceed pre-pandemic levels in 2022 and inventories are below the 5-year average. The OPEC+ supply agreement is expected to keep the market in a deficit and guidance for higher capacity will be needed in coming years given growing under-investment (Goldman Sachs Commodity Research).

In Alberta, physical markets and regional benchmark prices (e.g. Western Canadian Select "WCS" heavy oil) have improved with higher WTI prices. Athabasca expects current WCS differentials to remain stable with muted industry growth and improving basin egress, including the recently completed Enbridge Line 3 replacement. 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 have emerged for WCS heavy oil to be among the most valuable global crude benchmarks.

OUTLOOK

2021 Operational & Financial Guidance ($ millions, unless otherwise noted)	Annual
Production (boe/d)(1)	34,250
% Liquids(1)	~90%
Adjusted Funds Flow(1)(2)	$190
Free Cash Flow(1)(2)	$90
Capital Expenditures	$100
Thermal Oil	$95
Light Oil	$5

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP measures and production disclosure.
(2) 2021 strip pricing at October 4, 2021: US$67.50 WTI, US$12.40 WCS differentials, C$3.64/mcf AECO, 0.80 US$/C$ FX.

On October 22, 2021, Athabasca announced the closing of US$350 million of 5-year Senior Secured Notes and a $110 million reserve based credit facility. The refinanced capital structure provides certainty to shareholders of the Company's ability to utilize free cash flow to further reduce debt and enhance long-term resiliency.

Athabasca is increasing 2021 guidance for production to 34,250 boe/d (was 32,000 – 34,000 boe/d), Adjusted Funds Flow to $190 million and Free Cash Flow to $90 million, and reiterating the $100 million capital expenditures guidance.

Athabasca has commenced its 2022 hedging programing which includes 13,500 bbl/d of fixed WCS swaps at an average price of approximately US$54 (implied WTI of approximately US$66.50 assuming a US$12.50 WCS differential). These swaps fully protect the sustaining capital program down to approximately US$50 WTI. Additional hedges are anticipated to include collars and puts to strategically balance downside protection while maintaining upside exposure to the current price environment.

CONSOLIDATED RESULTS

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

Consolidated Operating Results

	Three months ended September 30, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
PRODUCTION				
Bitumen (bbl/d)	26,729	20,231	26,374	22,043
Oil and condensate (bbl/d)[1]	3,296	6,297	3,688	5,213
Natural gas (Mcf/d)[1]	20,304	27,414	21,087	23,129
Other natural gas liquids (bbl/d)[1]	846	964	862	785
Total (boe/d)[1]	34,255	32,061	34,439	31,896

(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 September 30, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
Petroleum, natural gas and midstream sales[1]	$ 291,300	$ 134,188	$ 756,450	$ 328,725
Royalties	(9,120)	(1,318)	(19,745)	(4,247)
Cost of diluent[1]	(89,149)	(36,064)	(255,071)	(154,594)
Operating expenses	(47,356)	(29,365)	(132,269)	(98,173)
Transportation and marketing[2]	(25,094)	(17,270)	(69,660)	(60,137)
Operating Income (Loss)[3]	120,581	50,171	279,705	11,574
Realized gain (loss) on commodity risk management contracts	(27,839)	(7,359)	(66,776)	38,502
OPERATING INCOME (LOSS) NET OF REALIZED HEDGING[3]	$ 92,742	$ 42,812	$ 212,929	$ 50,076
REALIZED PRICES				
Heavy oil (Blended bitumen) ($/bbl)	$ 70.13	$ 39.59	$ 63.12	$ 28.73
Oil and condensate ($/bbl)	83.21	48.41	75.08	41.69
Natural gas ($/Mcf)	3.84	2.34	3.65	2.18
Other natural gas liquids ($/bbl)	53.08	26.04	46.24	18.97
Realized price (net of cost of diluent) ($/boe)	60.40	33.62	52.96	19.54
Royalties ($/boe)	(2.73)	(0.45)	(2.09)	(0.48)
Operating expenses ($/boe)	(14.15)	(10.06)	(13.97)	(11.02)
Transportation and marketing ($/boe)	(7.50)	(5.92)	(7.36)	(6.75)
Operating Netback ($/boe)[3]	36.02	17.19	29.54	1.29
Realized gain (loss) on commodity risk mgmt. contracts ($/boe)	(8.32)	(2.52)	(7.05)	4.32
OPERATING NETBACK NET OF REALIZED HEDGING ($/boe)[3]	$ 27.70	$ 14.67	$ 22.49	$ 5.61

(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) Transportation and marketing excludes non-cash costs of $0.6 million and $0.9 million for the three and nine months ended September 30, 2021.
(3) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures and production disclosure.

Consolidated Segments Income (Loss)

($ Thousands)	Three months ended September 30, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
Operating Income (Loss) Net of Realized Hedging[1]	$ 92,742	$ 42,812	$ 212,929	$ 50,076
Non-cash transportation and marketing	(557)	—	(929)	—
Unrealized gain (loss) on commodity risk management contracts	(6,076)	(6,827)	(62,598)	8,443
Impairment loss	—	—	—	(471,839)
Depletion and depreciation	(23,579)	(29,553)	(71,377)	(84,583)
Gain (loss) on sale of assets	19,743	29	20,100	21,231
Exploration and non-producing asset expenses	(1,311)	(9,771)	(2,394)	(21,896)
CONSOLIDATED SEGMENTS INCOME (LOSS)	$ 80,962	$ (3,310)	$ 95,731	$ (498,568)

(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 September 30, 2021	2020	Nine months ended September 30, 2021	2020
Thermal Oil Division	$ 15,228	$ 10,454	$ 69,630	$ 32,872
Light Oil Division	128	1,917	1,640	61,534
Corporate assets	252	10	2,520	32
Total capital expenditures(1)(2)(3)	15,608	12,381	73,790	94,438
Less: Greater Kaybob capital-carry	—	—	—	(22,740)
TOTAL CAPITAL EXPENDITURES NET OF CAPITAL-CARRY(4)	$ 15,608	$ 12,381	$ 73,790	$ 71,698

(1) For the three and nine months ended September 30, 2021, expenditures include capitalized cash based stock-based compensation costs of $0.3 million and $2.5 million (three and nine months ended September 30, 2020 - $nil).
(2) For the three and nine months ended September 30, 2021, expenditures include capitalized staff costs of $1.5 million and $4.8 million (three and nine months ended September 30, 2020 - $1.1 million and $4.4 million).
(3) Excludes non-cash capitalized stock-based compensation and non-cash capitalized decommissioning obligation asset costs.
(4) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

THERMAL OIL DIVISION

Athabasca's Thermal Oil Division consists of its cornerstone producing Leismer asset, its producing Hangingstone asset, the high-quality Corner development asset and the Dover West exploration asset in the Athabasca region of northeastern Alberta. The Thermal Oil Division underpins the Company's low corporate production decline and low relative sustaining capital requirements, supporting significant free cash flow 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. The Hangingstone Project was restarted on September 1, 2020 in response to improved oil prices and has now achieved pre shut-in production levels.

(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 September 30, 2021	2020	Nine months ended September 30, 2021	2020
VOLUMES				
Bitumen production (bbl/d)	18,023	18,434	17,341	18,562
Bitumen sales (bbl/d)	19,349	18,942	17,379	18,682
Heavy oil (blended bitumen) sales (bbl/d)	26,245	25,519	24,276	26,017

($ Thousands, unless otherwise noted)	Three months ended September 30, 2021	2020	Nine months ended September 30, 2021	2020
Heavy oil (blended bitumen) sales	$ 168,545	$ 93,523	$ 418,148	$ 208,731
Cost of diluent	(58,623)	(33,648)	(160,481)	(116,858)
Total bitumen sales	109,922	59,875	257,667	91,873
Royalties	(4,742)	(492)	(9,135)	(1,406)
Operating expenses - non-energy	(13,133)	(10,956)	(34,528)	(34,532)
Operating expenses - energy	(12,920)	(7,743)	(34,974)	(22,833)
Transportation and marketing	(13,110)	(12,010)	(35,971)	(33,839)
LEISMER OPERATING INCOME (LOSS)(1)	$ 66,017	$ 28,674	$ 143,059	$ (737)
REALIZED PRICE				
Heavy oil (blended bitumen) sales ($/bbl)	$ 69.80	$ 39.84	$ 63.09	$ 29.28
Bitumen sales ($/bbl)	$ 61.75	$ 34.36	$ 54.31	$ 17.95
Royalties ($/bbl)	(2.66)	(0.28)	(1.93)	(0.27)
Operating expenses - non-energy ($/bbl)	(7.38)	(6.29)	(7.28)	(6.75)
Operating expenses - energy ($/bbl)	(7.26)	(4.44)	(7.37)	(4.46)
Transportation and marketing ($/bbl)	(7.36)	(6.89)	(7.58)	(6.61)
LEISMER OPERATING NETBACK ($/bbl)(1)	$ 37.09	$ 16.46	$ 30.15	$ (0.14)

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

As a result of the infill wells being on production late in the second quarter of 2021, the Leismer bitumen production increased to 18,023 bbl/day for the third quarter of 2021 compared to 17,341 bbl/d for the nine months ended September 30, 2021.

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

Total operating expenses were $14.64/bbl in the third quarter of 2021 and $14.65/bbl in the first nine months of 2021, compared to $10.73/bbl and $11.21/bbl respectively in the comparable periods of 2020. Energy operating costs per barrel increased in 2021 relative to the prior year periods due to higher natural gas and electricity prices in 2021.

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 September 30,		Nine months ended September 30,	
	2021	2020	2021	2020
VOLUMES				
Bitumen production (bbl/d)	8,706	1,797	9,033	3,481
Bitumen sales (bbl/d)	9,503	953	9,231	3,986
Heavy oil (blended bitumen) sales (bbl/d)	13,244	1,367	13,387	5,910

	Three months ended September 30,		Nine months ended September 30,	
($ Thousands, unless otherwise noted)	2021	2020	2021	2020
Heavy oil (blended bitumen) and midstream sales	$ 86,224	$ 4,398	$ 230,834	$ 42,574
Cost of diluent	(30,526)	(2,416)	(94,590)	(37,736)
Total bitumen and midstream sales	55,698	1,982	136,244	4,838
Royalties	(2,159)	—	(4,333)	(187)
Operating expenses - non-energy	(5,655)	(1,208)	(15,633)	(10,876)
Operating expenses - energy	(9,810)	(894)	(28,656)	(8,905)
Transportation and marketing(1)	(9,295)	(1,710)	(26,149)	(15,019)
HANGINGSTONE OPERATING INCOME (LOSS)(2)	$ 28,779	$ (1,830)	$ 61,473	$ (30,149)
REALIZED PRICE				
Heavy oil (blended bitumen) and midstream sales ($/bbl)	$ 70.77	$ 34.97	$ 63.16	$ 26.29
Bitumen and midstream sales ($/bbl)	$ 63.71	$ 22.61	$ 54.06	$ 4.43
Royalties ($/bbl)	(2.47)	—	(1.72)	(0.17)
Operating expenses - non-energy ($/bbl)	(6.47)	(13.78)	(6.20)	(9.96)
Operating expenses - energy ($/bbl)	(11.22)	(10.20)	(11.37)	(8.15)
Transportation and marketing ($/bbl)	(10.63)	(19.50)	(10.38)	(13.75)
HANGINGSTONE OPERATING NETBACK ($/bbl)(2)	$ 32.92	$ (20.87)	$ 24.39	$ (27.60)

(1) Transportation and marketing excludes non-cash costs of $0.6 million and $0.9 million for the three and nine months ended September 30, 2021.
(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures and production disclosure.

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

The Hangingstone Operating Netbacks are higher in 2021 primarily due to higher WCS benchmark oil prices and lower non-energy operating costs.

Total operating expenses were $17.69/bbl in the third quarter of 2021 and $17.57/bbl in the first nine months of 2021, compared to $23.98/bbl and $18.11/bbl respectively in the comparable periods of 2020. Non-energy costs per barrel decreased relative to the prior year periods due to several cost optimization initiatives implemented in 2020 and 2021. Energy operating costs per barrel increased relative to the prior year periods primarily due to higher natural gas and electricity prices in 2021.

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 September 30, 2021	2020	Nine months ended September 30, 2021	2020
VOLUMES				
Bitumen production (bbl/d)	26,729	20,231	26,374	22,043
Bitumen sales (bbl/d)	28,852	19,895	26,610	22,668
Heavy oil (blended bitumen) sales (bbl/d)	39,489	26,886	37,663	31,927

($ Thousands, unless otherwise noted)	Three months ended September 30, 2021	2020	Nine months ended September 30, 2021	2020
Heavy oil (blended bitumen) and midstream sales	$ 254,769	$ 97,921	$ 648,982	$ 251,305
Cost of diluent	(89,149)	(36,064)	(255,071)	(154,594)
Total bitumen and midstream sales	165,620	61,857	393,911	96,711
Royalties	(6,901)	(492)	(13,468)	(1,593)
Operating expenses - non-energy	(18,788)	(12,164)	(50,161)	(45,408)
Operating expenses - energy	(22,730)	(8,637)	(63,630)	(31,738)
Transportation and marketing(1)	(22,405)	(13,720)	(62,120)	(48,858)
THERMAL OIL OPERATING INCOME (LOSS)(2)	$ 94,796	$ 26,844	$ 204,532	$ (30,886)
REALIZED PRICE				
Heavy oil (blended bitumen) and midstream sales ($/bbl)	$ 70.13	$ 39.59	$ 63.12	$ 28.73
Bitumen and midstream sales ($/bbl)	$ 62.39	$ 33.80	$ 54.22	$ 15.57
Royalties ($/bbl)	(2.60)	(0.27)	(1.85)	(0.26)
Operating expenses - non-energy ($/bbl)	(7.08)	(6.65)	(6.90)	(7.31)
Operating expenses - energy ($/bbl)	(8.56)	(4.72)	(8.76)	(5.11)
Transportation and marketing ($/bbl)	(8.44)	(7.50)	(8.55)	(7.87)
THERMAL OIL OPERATING NETBACK ($/BBL)(2)	$ 35.71	$ 14.66	$ 28.16	$ (4.98)

(1) Transportation and marketing excludes non-cash costs of $0.6 million and $0.9 million for the three and nine months ended September 30, 2021.
(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures and production disclosure.

Thermal Oil Segment Income (Loss)

($ Thousands)	Three months ended September 30, 2021	2020	Nine months ended September 30, 2021	2020
Thermal Oil Operating Income (Loss)(1)	$ 94,796	$ 26,844	$ 204,532	$ (30,886)
Non-cash transportation and marketing	(557)	—	(929)	—
Impairment loss	—	—	—	(207,884)
Depletion and depreciation	(12,122)	(10,905)	(34,871)	(35,795)
Gain (loss) on sale of assets	19,743	29	20,000	21,231
Exploration and non-producing asset expenses	(1,311)	(9,771)	(2,394)	(21,896)
THERMAL OIL SEGMENT INCOME (LOSS)	$ 100,549	$ 6,197	$ 186,338	$ (275,230)

(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. Compared to the same periods of 2020, depletion decreased in the first nine months of 2021 due to the impairment and increased in the third quarter of 2021 due to the higher Thermal Oil production associated with the restart of Hangingstone. Non-producing asset expenses related to Hangingstone costs incurred during its suspension, were mainly comprised of committed transportation and utilities distribution costs, and excluded costs directly associated with suspending the asset which were recognized in restructuring expenses.

During the third quarter of 2021, Athabasca recorded a gain of $19.7 million, net of transaction costs, on the sale of its 20,000 bbl/d Trans Mountain Expansion Project pipeline service. During the second quarter of 2020, Athabasca recorded a gain of $21.0 million on a royalty transaction with Burgess Energy Holdings LLC 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 million were allocated to Leismer and Corner, and reduced the carrying value of those assets.

Thermal Oil Capital Expenditures

($ Thousands)	Three months ended September 30, 2021	2020	Nine months ended September 30, 2021	2020
Leismer Project	$ 12,920	$ 6,216	$ 64,332	$ 27,143
Hangingstone Project	2,238	4,122	5,099	5,464
Other Thermal Oil exploration	70	116	199	265
TOTAL THERMAL OIL CAPITAL EXPENDITURES[1]	$ 15,228	$ 10,454	$ 69,630	$ 32,872

(1) For the three and nine months ended September 30, 2021, capital expenditures include $1.0 million and $3.1 million of capitalized staff costs (three and nine months ended September 30, 2020 - $0.6 million and $2.4 million).

Thermal Oil capital expenditures for the first nine months of 2021 of $69.6 million were primarily related to sustaining operations at Leismer along with routine pump replacements across both assets. The company drilled a new well pair at Pad 7 and two infill wells at Pad 6 which were brought on stream in late June with production currently ramping up. The Company completed drilling five well pairs at Pad 8 in May and construction on the pipeline and surface facilities was completed during the third quarter of 2021. Pad 8 commenced steaming in October with first production expected in early 2022.

LIGHT OIL DIVISION

Athabasca produces light oil and liquids-rich natural gas from unconventional reservoirs. Development has been focused on the Montney in the Greater Placid area and the Duvernay in the Greater Kaybob area near the town of Fox Creek, Alberta. As at December 31, 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 205,000 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 September 30, 2021	2020	Nine months ended September 30, 2021	2020
PRODUCTION[1]				
Oil and condensate (bbl/d)	3,296	6,297	3,688	5,213
Natural gas (Mcf/d)	20,304	27,414	21,087	23,129
Other natural gas liquids (bbl/d)	846	964	862	785
Total (boe/d)	7,526	11,830	8,065	9,853
Consisting of:				
Greater Placid area (boe/d)	4,205	6,522	4,446	5,067
% Liquids	44%	50%	44%	49%
Greater Kaybob area (boe/d)	3,321	5,308	3,619	4,786
% Liquids	69%	76%	72%	74%

(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 September 30, 2021	2020	Nine months ended September 30, 2021	2020
Petroleum and natural gas sales	$ 36,531	$ 36,267	$ 107,468	$ 77,420
Royalties	(2,219)	(826)	(6,277)	(2,654)
Operating expenses	(5,838)	(8,564)	(18,478)	(21,027)
Transportation and marketing	(2,689)	(3,550)	(7,540)	(11,279)
LIGHT OIL OPERATING INCOME (LOSS)[1]	$ 25,785	$ 23,327	$ 75,173	$ 42,460
REALIZED PRICES				
Oil and condensate ($/bbl)	$ 83.21	$ 48.41	$ 75.08	$ 41.69
Natural gas ($/Mcf)	3.84	2.34	3.65	2.18
Other natural gas liquids ($/bbl)	53.08	26.04	46.24	18.97
Realized price ($/boe)	52.76	33.32	48.81	28.68
Royalties ($/boe)	(3.20)	(0.76)	(2.85)	(0.98)
Operating expenses ($/boe)	(8.43)	(7.87)	(8.39)	(7.79)
Transportation and marketing ($/boe)	(3.88)	(3.26)	(3.42)	(4.18)
LIGHT OIL OPERATING NETBACK ($/boe)[1]	$ 37.25	$ 21.43	$ 34.15	$ 15.73

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

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

Athabasca generated Light Oil Operating Income of $25.8 million ($37.25/boe Operating Netback) in the third quarter and $75.2 million ($34.15/boe Operating Netback) in first nine months of 2021. The Operating Income and Operating Netbacks were higher than in 2020 primarily due to stronger commodity pricing. Royalties increased in 2021 compared to 2020 due to stronger commodity prices.

Transportation and marketing costs decreased in the first nine months of 2021 due to a natural gas transportation contract that ended in the fourth quarter of 2020.

Light Oil Segment Income (Loss)

($ Thousands)	Three months ended September 30, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
Light Oil Operating Income (Loss)[1]	$ 25,785	$ 23,327	$ 75,173	$ 42,460
Impairment loss	—	—	—	(263,955)
Depletion and depreciation	(11,457)	(18,648)	(36,506)	(48,788)
Gain (loss) on sale of assets	—	—	100	—
LIGHT OIL SEGMENT INCOME (LOSS)	$ 14,328	$ 4,679	$ 38,767	$ (270,283)

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

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

Light Oil Capital Expenditures

($ Thousands)	Three months ended September 30, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
Greater Placid	$ 717	$ 599	$ 2,406	$ 22,313
Greater Kaybob	(589)	1,318	(766)	39,221
Total Light Oil capital expenditures[1]	128	1,917	1,640	61,534
Less: Greater Kaybob capital-carry	—	—	—	(22,740)
TOTAL CAPITAL EXPENDITURES NET OF CAPITAL-CARRY[2]	$ 128	$ 1,917	$ 1,640	$ 38,794

(1) For the three and nine months ended September 30, 2021, capital expenditures include $0.5 million and $1.7 million of capitalized staff costs (three and nine months ended September 30, 2020 - $0.5 million and $2.0 million).
(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

Minimal capital expenditures were incurred in the first nine months of 2021. The Greater Kaybob capital expenditures are in a credit balance due to credits booked relating to the Final Statement of Adjustments for the Capital-Carry. The following table summarizes Athabasca's well activity for the three and nine months ended September 30, 2021 and 2020:

	Three months ended September 30,				Nine months ended September 30,			
	2021		2020		2021		2020	
Well activity[1]	Gross	Net	Gross	Net	Gross	Net	Gross	Net
GREATER PLACID								
Wells drilled	—	—	—	—	—	—	—	—
Wells completed	—	—	—	—	—	—	7	4.9
Wells brought on production	—	—	—	—	—	—	10	7.0
GREATER KAYBOB								
Wells drilled	—	—	—	—	—	—	8	2.4
Wells completed	—	—	—	—	—	—	13	3.7
Wells brought on production	—	—	4	1.1	—	—	17	4.9

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

CORPORATE REVIEW

Liquidity and Capital Resources

Funding

Athabasca's strategy is to position itself as a low leveraged company that will generate significant Free Cash Flow through its low-decline, oil weighted asset base. The refinanced capital structure provides certainty to shareholders of the Company's ability to utilize Free Cash Flow to further reduce debt and enhance long-term resiliency. The Company is focused on utilizing its Free Cash Flow to increase margins and provide superior shareholder returns. 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 equivalents and available credit facilities.

As at September 30, 2021, Athabasca had liquidity of $277.6 million representing its unrestricted cash and cash equivalents balance and unutilized portion of the unsecured letter of credit facility.

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

Athabasca intends to use the net proceeds of the Offering, and cash on hand to redeem its US$450 million 2022 Notes. Athabasca issued a notice on October 7, 2021 to conditionally redeem its 2022 Notes at a redemption price of 100.0% of the principal amount of the 2022 Notes plus accrued and unpaid interest to, but excluding, the redemption date. The redemption date is November 6, 2021.

On October 22, 2021 Athabasca entered into an amended and restated credit agreement with a syndicate of financial institutions. The amended and restated credit agreement provides for a C$110 million reserves-based secured credit facility with a maturity date in October 2023. Existing outstanding letters of credit are no longer cash collateralized and the Company concurrently cancelled its cash collateralized Letter of Credit Facility.

For the balance of 2021 and 2022, it is anticipated that Athabasca's Light Oil and Thermal Oil capital and operating activities will be funded through cash flow from operating activities and existing cash and cash equivalents.

Indebtedness

Athabasca had the following debt instruments and credit facilities in place as at September 30, 2021:

2022 Notes

As at ($ Thousands)	September 30, 2021	December 31, 2020
2022 Notes[1]	$ 573,345	$ 572,940
Debt issuance costs	(47,081)	(47,081)
Amortization of debt issuance costs	42,164	33,639
TOTAL LONG-TERM DEBT	$ 568,428	$ 559,498

(1) As at September 30, 2021, the US dollar denominated 2022 Notes were translated into Canadian dollars at the period end exchange rate of US$1.00 = C$1.2741 (December 31, 2020 – C$1.2732).

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 were scheduled to mature on February 24, 2022.

Athabasca intends to use the net proceeds of the Offering, and cash on hand to redeem its US$450 million 2022 Notes. Athabasca issued a notice on October 7, 2021 to conditionally redeem its 2022 Notes at a redemption price of 100.0% of the principal amount plus accrued and unpaid interest to, but excluding, the redemption date. The redemption date is November 6, 2021 (See Financial Statement Note 19).

Credit Facility

In the second quarter of 2021, the Company's banking syndicate renewed the reserve-based credit facility (the "Credit Facility") which was scheduled to be renewed by November 30, 2021. As at September 30, 2021, the Company had no amounts drawn and no letters of credit issued under the Credit Facility. As at December 31, 2020, the Company had no amounts drawn and had $38.0 million of letters of credit issued under the Credit Facility.

Under the terms of the Credit Facility, Athabasca was 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 September 30, 2021, no restricted cash related to this Credit Facility was held in the cash-collateral account (December 31, 2020 - $38.5 million). The Credit Facility was secured by a first priority security interest on all present and after acquired property of the Company. The Credit Facility contained certain covenants that limited 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 Company was in compliance with all covenants.

In conjunction with the Offering, on October 22, 2021 Athabasca entered into an amended and restated credit agreement (the “Amended Credit Facility”) with a syndicate of financial institutions that provides for a $110 million reserves-based secured credit facility with a maturity date in October 2023 (See Financial Statement Note 19).

Cash-Collateralized Letter of Credit Facility

As at September 30, 2021, Athabasca maintained a $120.0 million cash-collateralized letter of credit facility (the “Letter of Credit Facility”) with a Canadian bank for issuing letters of credit to counterparties. The facility was available on a demand basis and letters of credit issued under the Letter of Credit Facility incurred an issuance fee of 0.25%. As at September 30, 2021, Athabasca had $45.6 million (December 31, 2020 - $96.0 million) in letters of credit issued under the Letter of Credit Facility.

Under the terms of the Letter of Credit Facility, Athabasca was 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 September 30, 2021, $46.1 million of restricted cash was held in the cash-collateral account (December 31, 2020 - $97.1 million). In conjunction with the Offering and the Amended Credit Facility, the Letter of Credit Facility was cancelled. The $45.6 million in letters of credit issued under the facility were transferred to the Amended Credit Facility and the $46.1 million of restricted cash was concurrently released (See Financial Statement Note 19).

Unsecured Letter of Credit Facility

Athabasca maintains a $40.0 million unsecured letter of credit facility (the “Unsecured Letter of Credit Facility”) with a Canadian bank and is supported by a performance security guarantee from Export Development Canada. 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 September 30, 2021, the Company had $36.4 million of letters of credit issued under the Unsecured Letter of Credit Facility (December 31, 2020 - $39.7 million).

Financing and Interest

($ Thousands)	Three months ended September 30, 2021	2020	Nine months ended September 30, 2021	2020
Financing and interest expense on indebtedness	$ 14,583	$ 15,105	$ 43,581	$ 46,833
Amortization of debt issuance costs	2,958	2,625	8,525	7,994
Accretion of provisions	3,556	3,194	10,351	9,229
Interest expense on lease liability	294	363	934	1,135
TOTAL FINANCING AND INTEREST	$ 21,391	$ 21,287	$ 63,391	$ 65,191

During the three and nine months ended September 30, 2021 and 2020, financing and interest expenses were primarily attributable to the Company's 2022 Notes.

Foreign Exchange Gain (Loss), Net

($ Thousands)	Three months ended September 30, 2021	2020	Nine months ended September 30, 2021	2020
Unrealized foreign exchange gain (loss)	$ (9,211)	$ 9,994	$ 7,408	$ (18,186)
Realized foreign exchange gain (loss)	(375)	13	(1,650)	2,223
FOREIGN EXCHANGE GAIN (LOSS), NET	$ (9,586)	$ 10,007	$ 5,758	$ (15,963)

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 September 30, 2021, the following financial commodity risk management contracts were in place:

Instrument	Period	Volume		C$ Average Price(1)		US$ Average Price(1)
Sales contracts				*C$/bbl*		*US$/bbl*
WTI fixed price swaps	October - December 2021	5,000 bbl/d	$	80.27	$	63.00
WTI sold call options	October - December 2021	15,900 bbl/d	$	71.23	$	55.90
WTI/WCS differential swaps	October - December 2021	5,000 bbl/d	$	(16.50)	$	(12.95)
WCS fixed price swap	November - December 2021	1,500 bbl/d	$	75.24	$	59.05
WCS fixed price swap	January - March 2022	16,000 bbl/d	$	69.76	$	54.75
WCS fixed price swap	April - June 2022	14,000 bbl/d	$	68.79	$	53.99
WCS fixed price swap	July - December 2022	12,000 bbl/d	$	68.25	$	53.57
Purchase contracts				*C$/GJ*		*US$/GJ*
AECO fixed price swaps	October - December 2021	10,000 GJ/d	$	2.73	$	2.14

(1) The implied C$ or US$ Average Price per bbl or GJ, as applicable, was calculated using the September 30, 2021 exchange rate of US$1.00 = C$1.2741.

The following table summarizes the Company's net gain (loss) on commodity risk management contracts for the three and nine months ended September 30, 2021 and 2020:

($ Thousands)		Three months ended September 30, 2021		2020		Nine months ended September 30, 2021		2020
Unrealized gain (loss) on commodity risk mgmt. contracts	$	(6,076)	$	(6,827)	$	(62,598)	$	8,443
Realized gain (loss) on commodity risk mgmt. contracts		(27,839)		(7,359)		(66,776)		38,502
GAIN (LOSS) ON COMMODITY RISK MGMT. CONTRACTS, NET	$	(33,915)	$	(14,186)	$	(129,374)	$	46,945

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

As at September 30, 2021		Change in WTI: Increase of US$5.00/bbl		Change in WTI: Decrease of US$5.00/bbl		Change in WCS differential: Increase of US$1.00/bbl		Change in WCS differential: Decrease of US$1.00/bbl
Increase (decrease) to fair value of commodity risk management contracts	$	(42,106)	$	42,106	$	6,602	$	(6,602)

Additional financial commodity risk management has taken place subsequent to September 30, 2021, as noted in the table below:

Instrument	Period	Volume		C$ Average Price(1)		US$ Average Price(1)
Sales contracts				*C$/bbl*		*US$/bbl*
WTI collar	December 2021	5,500 bbl/d	$	63.71 - 128.68	$	50.00 - 101.00
WTI collar	January - March 2022	5,500 bbl/d	$	63.71 - 124.36	$	50.00 - 97.61
WTI collar	April - June 2022	6,000 bbl/d	$	63.71 - 123.95	$	50.00 - 97.29
WTI collar	July - December 2022	6,500 bbl/d	$	63.71 - 123.44	$	50.00 - 96.88
WTI collar	January - March 2023	4,000 bbl/d	$	70.08 - 105.63	$	55.00 - 82.91
Purchase contracts				*C$/GJ*		*US$/GJ*
AECO fixed price swaps	January - December 2022	5,000 GJ/d	$	3.85		3.02

(1) The implied C$ or US$ Average Price/bbl, as applicable, was calculated using the September 30, 2021 exchange rate of US$1.00 = C$1.2741.

Commitments and Contingencies

The following table summarizes Athabasca's estimated future unrecognized minimum commitments as at September 30, 2021 for the following five years and thereafter:

($ Thousands)		Remaining 2021	2022	2023	2024	2025	Thereafter	Total
Transportation and processing[1]	$	30,320	$ 117,512	$ 116,836	$ 112,421	$ 108,534	$1,252,909	$1,738,532
Interest expense on long-term debt[1]		—	22,647	—	—	—	—	22,647
Purchase commitments		6,084	12,017	4	—	—	—	18,105
TOTAL COMMITMENTS	$	36,404	$ 152,176	$ 116,840	$ 112,421	$ 108,534	$1,252,909	$1,779,284

(1) Commitments which are denominated in US dollars were translated into Canadian dollars at the September 30, 2021 exchange rate of US$1.00 = C$1.2741.

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

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

In the third quarter of 2021 Athabasca executed a sale and assignment agreement of its 20,000 bbl/d Trans Mountain Expansion Project pipeline service to a downstream player for $20 million cash consideration resulting in a $19.7 million gain on sale of asset, net of transaction costs. In the third quarter Athabasca also assigned its Keystone base service of 7,200 bbl/d to an industry counterparty and entered into a seven-year marketing agreement with the counterparty for 15,000 bbl/d. The marketing agreement has a pricing derivative when the Gulf Coast service becomes available that currently has no value but will be reassessed at future balance sheet dates. As a result of these third quarter transactions, the related service commitments were reduced by $1.4 billion.

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

Credit Risk

Credit risk is the risk of financial loss to Athabasca if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from Athabasca's cash balances, 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 three 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 September 30, 2021. Athabasca's risk management contracts are held with three counterparties, all of which are large reputable financial institutions, and management concluded that credit risk associated with these risk management contracts is low.

Interest Rate Risk

The Company's exposure to interest rate fluctuations on interest earned on its floating rate cash, cash equivalents and restricted cash balance at September 30, 2021 of $320.1 million (December 31, 2020 - $300.8 million), from a 1.0% change in interest rates, would have an annualized impact of approximately $3.2 million (year ended December 31, 2020 - $3.0 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 September 30, 2021	2020	Nine months ended September 30, 2021	2020
TOTAL GENERAL AND ADMINISTRATIVE	$ 3,866	$ 3,400	$ 11,447	$ 14,126
G&A per boe	$ 1.23	$ 1.15	$ 1.22	$ 1.62

During the nine months ended September 30, 2021, Athabasca's G&A expenses and G&A per boe decreased compared to the same period in the prior year primarily due to reduced salaries, benefits and professional fees.

Stock Based Compensation

During the three and nine months ended September 30, 2021, Athabasca's stock-based compensation expense was $1.1 million and $12.2 million compared to $0.6 million and $1.4 million in the respective prior year periods. The increase is primarily due to the increase in the fair value of the cash settled stock-based compensation plans during the first nine months of 2021 as a result of the increased share price on September 30, 2021.

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

In the third quarter of 2021, Athabasca assigned its 7,200 bbl/d Keystone base service from Hardisty to the US Gulf Coast and the Development Cost Agreement ("DCA") in relation to the Keystone XL pipeline to an industry counterparty resulting in a gain on the derecognition of the US$48 million ($60.6 million) DCA provision, a recovery of the US$25 million ($32.0 million) deposit and release of US$35.5 million ($45.5 million) in restricted cash that was securing existing letters of credit.

Income Taxes

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

As at September 30, 2021, the Company has approximately $3.2 billion in tax pools, including approximately $2.4 billion in non-capital losses and exploration tax pools available for immediate deduction against future income.

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 September 30, 2021, there were 530.7 million common shares outstanding, an aggregate of 24.5 million restricted share units and performance share units outstanding, 6.5 million stock options outstanding, 8.1 million deferred shares units outstanding and 10.2 million phantom share units outstanding. During the three and nine months ended September 30, 2021, Athabasca issued no common shares in respect of the Company's equity-settled share-based compensation plans as the RSU's and PSU's were settled with cash.

SUMMARY OF QUARTERLY RESULTS

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

	2021			2020				2019
($ Thousands, unless otherwise noted)	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	70.56	66.07	57.84	42.66	40.93	27.85	46.17	56.96
WTI (C$/bbl)	88.91	81.11	73.24	55.58	54.50	38.59	62.03	75.19
Western Canadian Select (C$/bbl)	71.77	66.96	57.40	43.40	42.39	22.41	34.11	54.27
Edmonton Par (C$/bbl)	83.70	77.07	66.44	49.98	49.54	29.55	51.62	67.99
Edmonton Condensate (C5+) (C$/bbl)	86.78	81.00	72.92	55.05	49.78	29.95	60.39	69.22
AECO (C$/GJ)	3.41	2.93	2.98	2.50	2.12	1.89	1.93	2.35
Chicago Citygate (US$/MMBtu)	4.08	2.79	6.47	2.27	1.83	1.61	1.74	2.20
Foreign exchange (USD : CAD)	1.26	1.23	1.27	1.30	1.33	1.39	1.34	1.32
CONSOLIDATED								
Petroleum and natural gas production (boe/d)(1)	34,255	34,659	34,401	34,233	32,061	27,067	36,557	36,403
Realized price (net of cost of diluent) ($/boe)	60.40	53.76	44.23	33.56	33.62	9.03	15.47	38.61
Petroleum, natural gas and midstream sales ($)(2)	291,300	243,868	221,282	162,815	134,188	56,037	138,500	188,101
Operating Income (Loss) ($)(1)	120,581	93,196	65,928	40,288	50,171	(18,269)	(20,328)	44,945
Operating Income (Loss) Net of Realized Hedging ($)(1)	92,742	75,372	44,815	30,935	42,812	6,166	1,098	42,881
Operating Netback ($/boe)(1)	36.02	31.09	21.12	12.88	17.19	(7.05)	(5.98)	14.51
Operating Netback Net of Realized Hedging ($/boe)(1)	27.70	25.14	14.36	9.89	14.67	2.37	0.33	13.84
Capital expenditures ($)	15,608	22,628	35,554	17,202	12,381	5,811	76,246	69,796
Capital Expenditures Net of Capital-Carry ($)(1)	15,608	22,628	35,554	17,202	12,381	5,811	53,506	46,259
THERMAL OIL DIVISION								
Bitumen production (bbl/d)	26,729	26,433	25,949	24,839	20,231	17,601	28,315	27,761
Bitumen sales volumes (bbl/d)	28,852	24,710	26,240	24,613	19,895	19,045	29,095	25,049
Realized bitumen price ($/bbl)	62.39	55.49	43.83	33.05	33.80	3.83	10.66	38.09
Heavy Oil (blended bitumen) and midstream sales ($)	254,769	207,503	186,710	132,635	97,921	39,231	114,153	156,197
Operating Income (Loss) ($)(1)	94,796	67,568	42,168	20,746	26,844	(24,619)	(33,111)	28,658
Operating Netback ($/bbl)(1)	35.71	30.05	17.85	9.17	14.66	(14.21)	(12.50)	12.44
Capital expenditures ($)	15,228	21,388	33,014	16,915	10,454	4,722	17,696	23,229
LIGHT OIL DIVISION								
Petroleum and natural gas production (boe/d)(1)	7,526	8,226	8,452	9,394	11,830	9,466	8,242	8,642
Realized price ($/boe)	52.76	48.58	45.45	34.92	33.32	19.51	32.46	40.13
Petroleum and natural gas sales ($)(2)	36,531	36,365	34,572	30,180	36,267	16,806	24,347	31,904
Operating Income (Loss) ($)(1)	25,785	25,628	23,760	19,542	23,327	6,350	12,783	16,287
Operating Netback ($/boe)(1)	37.25	34.23	31.24	22.61	21.43	7.37	17.04	20.49
Capital expenditures ($)	128	544	968	117	1,917	1,089	58,527	46,473
Capital Expenditures Net of Capital-Carry ($)(1)	128	544	968	117	1,917	1,089	35,787	22,936
OPERATING RESULTS								
Cash flow from operating activities ($)	75,743	36,183	1,138	16,079	(4,782)	(31,186)	(3,021)	32,975
Adjusted Funds Flow ($)(1)	72,233	50,228	18,961	10,753	14,617	(16,214)	(27,883)	21,478
Net income (loss) ($)	104,951	(13,944)	(17,472)	(56,891)	(18,818)	(65,335)	(516,481)	(8,757)
Net income (loss) per share - basic ($)	0.20	(0.03)	(0.03)	(0.11)	(0.04)	(0.12)	(0.99)	(0.02)
BALANCE SHEET ITEMS								
Cash and cash equivalents ($)	273,989	152,639	141,130	165,201	151,730	167,442	199,517	254,389
Restricted cash ($)	46,107	90,232	135,120	135,624	150,887	152,125	110,634	110,609
Capital-carry receivable (discounted) ($)(3)	—	—	—	—	—	—	—	22,602
Total assets ($)	1,510,924	1,466,102	1,443,246	1,425,984	1,425,343	1,468,248	1,599,860	2,093,465
Long-term debt ($)(3)	568,428	549,855	555,160	559,498	584,108	594,488	617,123	559,687
Shareholders' equity ($)	640,542	534,330	547,035	567,025	622,771	640,515	705,055	1,220,062

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures and production disclosure.
(2) Includes intercompany NGLs (i.e. condensate) sold by the Light Oil segment to the Thermal Oil segment for use as diluent that is eliminated on consolidation.
(3) Balances include the current and long-term portions as reported in the consolidated balance sheets.

Refer to the Results of Operations and other sections of this MD&A for detailed financial and operational variances between reporting periods as well as to Athabasca's previously issued annual and quarterly MD&As for changes in prior periods.

ACCOUNTING POLICIES AND ESTIMATES

During the three and nine months ended September 30, 2021, there were no changes to Athabasca's accounting policies or use of estimates and judgments in the preparation of the consolidated financial statements and the notes thereto. A summary of the significant accounting policies, including the use of estimates and judgments, used by Athabasca can be found in Note 3 of the December 31, 2020 audited consolidated financial statements. All of the estimates and judgments are subject to measurement uncertainty and changes in these estimates could materially impact the consolidated financial statements of future periods and have a significant impact on net income (loss).

In March 2020, the COVID-19 outbreak was declared a pandemic by the World Health Organization and 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 started to reopen along with positive developments on the vaccine front leading to a recovery in oil prices in late 2020 and into the first nine months of 2021. Despite strengthening oil fundamentals sentiment remains fragile with potential demand impacts of COVID-19 variants and supply uncertainty from US shale and the return of OPEC+ barrels to the market. Accordingly, 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.

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", "Consolidated Operating Income (Loss) Net of Realized Hedging", "Consolidated Operating Netback Net of Realized Hedging", "Consolidated Capital Expenditures Net of Capital-Carry" and “Free Cash Flow” 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 and nine months ended September 30, 2021 and 2020 to Adjusted Funds Flow:

	Three months ended September 30,		Nine months ended September 30,	
($ Thousands)	2021	2020	2021	2020
Cash flow from operating activities	$ 75,743	$ (4,782)	$ 113,064	$ (38,989)
Restructuring expenses	—	—	—	5,703
Changes in non-cash working capital	(3,580)	15,653	26,922	(6,056)
Settlement of provisions	70	3,746	1,436	9,862
ADJUSTED FUNDS FLOW	$ 72,233	$ 14,617	$ 141,422	$ (29,480)

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 Operating Income (Loss) measures in this MD&A are calculated by subtracting the cost of diluent, royalties, operating expenses and cash transportation & marketing expenses from petroleum, natural gas and midstream sales. The Operating Netback measures are calculated by dividing the respective projects Operating Income (Loss) by its respective sales volumes and is presented on a per boe basis. The Operating Income (Loss) and Operating Netback measures allow management and others to evaluate the production results from the Company’s assets. The table on page 12 reconciles Light Oil Operating Income (Loss) to *Note 12 - Segmented Information* in the consolidated financial statements for the three and nine months ended September 30, 2021. The table on page 9 reconciles Thermal Oil Operating Income (Loss) to *Note 12 - Segmented Information* in the consolidated financial statements for the three and nine months ended September 30, 2021.

The Consolidated Operating Income (Loss) Net of Realized Hedging measure in this MD&A is calculated by adding or subtracting realized gains (losses) on commodity risk management contracts, royalties, the cost of diluent, operating expenses and cash transportation & marketing expenses from petroleum, natural gas and midstream sales. The Consolidated Operating Netback Net of Realized Hedging measure is calculated by dividing Consolidated Operating Income (Loss) Net of Realized Hedging by the total sales volumes and is presented on a per boe basis. The Consolidated Operating Income (Loss) Net of Realized Hedging and the Consolidated Operating Netback Net of Realized Hedging measures allow management and others to evaluate the production results from the Company's Light Oil and Thermal Oil assets combined together including the impact of realized commodity risk management gains or losses. The table on page 5 reconciles Consolidated Operating Income (Loss) Net of Realized Hedging to *Note 12 - Segmented Information* in the consolidated financial statements for the three and nine months ended September 30, 2021.

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 6 and 12. These measures allow management and others to evaluate the true net cash outflow related to Athabasca's capital expenditures.

The Free Cash Flow measure in this MD&A is calculated by subtracting Capital Expenditures Net of Capital-Carry from Adjusted Funds Flow. This measure allows management and others to evaluate Athabasca's ability to generate funds to finance operations and capital expenditures.

Production volumes details

Production		Three months ended September 30, 2021	2020	Nine months ended September 30, 2021	2020
Greater Placid:					
Condensate NGLs	bbl/d	1,312	2,612	1,430	2,005
Other NGLs	bbl/d	522	632	517	458
Natural gas(1)	mcf/d	14,226	19,668	14,994	15,624
Total Greater Placid	boe/d	4,205	6,522	4,446	5,067
Greater Kaybob:					
Oil(2)	bbl/d	1,984	3,685	2,258	3,208
Other NGLs	bbl/d	324	332	345	327
Natural gas(1)	mcf/d	6,078	7,746	6,093	7,505
Total Greater Kaybob	boe/d	3,321	5,308	3,619	4,786
Light Oil:					
Oil(2)	bbl/d	1,984	3,685	2,258	3,208
Condensate NGLs	bbl/d	1,312	2,612	1,430	2,005
Oil and condensate NGLs	bbl/d	3,296	6,297	3,688	5,213
Other NGLs	bbl/d	846	964	862	785
Natural gas(1)	mcf/d	20,304	27,414	21,087	23,129
Total Light Oil division	boe/d	7,526	11,830	8,065	9,853
Total Thermal Oil division bitumen	bbl/d	26,729	20,231	26,374	22,043
Total Company production	boe/d	34,255	32,061	34,439	31,896

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

This MD&A also makes reference to Athabasca's forecasted total average daily production of 32,000 - 34,000 boe/d for 2021. Athabasca expects that approximately 78% of that production will be comprised of bitumen, 10% shale gas, 6% tight oil, 4% condensate natural gas liquids and 2% other natural gas liquids.

Liquids:		Three months ended September 30, 2021	2020	Nine months ended September 30, 2021	2020
Greater Placid:					
Condensate NGLs	bbl/d	1,312	2,612	1,430	2,005
Other NGLs	bbl/d	522	632	517	458
Total Greater Placid Liquids	bbl/d	1,834	3,244	1,947	2,463
as % of Greater Placid prod.		44%	50%	44%	49%
Greater Kaybob:					
Oil	bbl/d	1,984	3,685	2,258	3,208
Other NGLs	bbl/d	324	332	345	327
Total Greater Kaybob Liquids	bbl/d	2,308	4,017	2,603	3,535
as % of Greater Kaybob prod.		69%	76%	72%	74%
Total Light Oil:					
Oil and condensate NGLs	bbl/d	3,296	6,297	3,688	5,213
Other NGLs	bbl/d	846	964	862	785
Total Light Oil division Liquids	bbl/d	4,142	7,261	4,550	5,998
as % of Light Oil production		55%	61%	56%	61%
Total Company:					
Total Light Oil division Liquids	bbl/d	4,142	7,261	4,550	5,998
Total Thermal Oil division bitumen	bbl/d	26,729	20,231	26,374	22,043
Total Company Liquids	bbl/d	30,871	27,492	30,924	28,041
as % of Company production		90%	86%	90%	88%

Comparative Figures

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

Disclosure Control and Procedures

Athabasca is required to comply with National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109"). NI 52-109 requires that Athabasca disclose in its interim MD&A any material weaknesses in Athabasca's internal control over financial reporting and/or any changes in Athabasca's internal control over financial reporting that occurred during the period that have materially affected, or are reasonably likely to materially affect, Athabasca's internal controls over financial reporting. As part of this assessment management considered the impact of the Company wide work from home initiative as a result of COVID-19 on the Company’s internal control environment. Athabasca confirms that no material weaknesses or such changes were identified in Athabasca's internal controls over financial reporting during the third quarter of 2021.

Risk Factors

Factors currently influencing the Company’s ability to succeed include, but are not limited to, the following:

Operational risks

- the performance of the Company’s assets;
- reservoir impairment when shutting in or curtailing production from oil and gas assets;
- Athabasca’s exploration and development budget and Athabasca’s capital expenditure programs;
- failure to realize anticipated benefits of acquisitions or divestments;
- uncertainties inherent in estimating quantities of Proved Reserves, Probable Reserves and Contingent Resources;
- the timing of certain of Athabasca’s operations and projects, including the commencement of its planned Thermal Oil Division development projects, the exploration and development of Athabasca’s Light Oil assets and the levels and timing of anticipated production;
- dependence upon Murphy as a working interest participant in its Light Oil assets and as operator of the Greater Kaybob assets;
- risks and uncertainties inherent in Athabasca’s operations, including those related to exploration, development and production of reserves and resources;

- risks related to gathering and processing facilities and pipeline systems;
- reliance on third party infrastructure;
- 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 Company's indebtedness;
- risks related to the Common Shares;
- risks of cybersecurity threats including the possibility of potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of our information technology systems; and
- negative economic impacts as a result of the spread of COVID-19 (coronavirus).

Legal and compliance risks

- the regulatory framework governing royalties, taxes, environmental matters and foreign investment in the jurisdictions in which Athabasca conducts and will conduct its business;
- risks related to Athabasca's filings with taxation authorities, including the risk of tax related reviews and reassessments;
- 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 and related on stream timing 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; Adjusted Funds Flow; Free Cash Flow 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; 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 10 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 10 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