Management's Discussion and Analysis

Q2 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 July 29, 2020 and should be read in conjunction with the audited consolidated financial statements of the Company for the years ended December 31, 2019 and 2018. 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 4, 2020 ("AIF"). The Company's common shares are listed on the Toronto Stock Exchange under the trading symbol "ATH".

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ATHABASCA'S STRATEGY

Athabasca is a liquids-weighted intermediate producer with exposure to Canada's most active resource plays (Montney, Duvernay, Oil Sands). The Company offers investors exposure to oil prices and is focused on maximizing profitability through prudent capital activity in its Light Oil and Thermal Oil operations. The Company's strategy is guided by:

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

Athabasca remains focused on maximizing corporate funds flow and maintaining strong 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.

RECENT AND SECOND QUARTER 2020 HIGHLIGHTS

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, enact emergency measures to combat the spread of the virus. In the second quarter of 2020, economies have started to reopen leading to a partial recovery and stabilization in oil prices.

Corporate

- Second quarter production of 27,067 boe/d (87% liquids weighting). Lower production reflected voluntary temporary curtailments in response to extreme pricing volatility during the quarter.
- Second quarter Operating Income(1) of $6.2 million and Adjusted Funds Flow(1) of $(16.2) million was significantly impacted by realized price declines.
- Liquidity of $170 million, of which $167.4 million is unrestricted cash at June 30, 2020.
- In response to the macro-economic volatility resulting from the COVID-19 pandemic, the Company responded swiftly to bolster liquidity and resiliency of its operations. Actions included reducing 2020 capital by $40 million to an estimated $85 million ($25.7 million capital budget for Q3 – Q4 2020), reducing G&A costs by moving to an 80% work week for Corporate staff and upsizing the previously completed Contingent Bitumen Royalty with Burgess Energy Holdings L.L.C. (the "Royalty") for additional cash consideration of $70 million on April 28, 2020.

Light Oil Division

- Second quarter production of 9,466 boe/d (62% liquids).
- 10 Gross (7 net) Montney wells and 13 Gross (3.8 net) Duvernay wells tested and placed on-production. The Company elected to defer initial production from new development wells until early in the third quarter of 2020 to maximize netback and long-term shareholder value during this low commodity pricing environment.
- Second quarter operating Income(1) of $6.4 million and an Operating Netback(1) of $7.37/boe.
- Capital Expenditures Net of Capital-Carry(1) of $1.1 million in the second quarter of 2020 as the Company completed its winter program. Minimal activity is planned for the balance of 2020.

Thermal Oil Division

- Second quarter production of 17,601 bbl/d. Lower production reflected curtailments at Leismer and the suspension of the Hangingstone SAGD operations in response to the low commodity pricing environment.
- In April Leismer was initially curtailed down to 15,000 bbl/d but with the recovery in oil prices it was ramped back up and has recovered to approximately 18,500 bbl/d in July 2020.
- Second quarter operating Loss(1) of $(24.6) million was significantly impacted by realized price declines.
- Second quarter capital expenditures of $4.7 million included maintenance and routine pump changes. The Company has completed all major 2020 capital projects with minimal activity currently planned for the balance of 2020.

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

FINANCIAL & OPERATIONAL HIGHLIGHTS

The following tables summarize selected financial and operational information of the Company for the periods indicated:

($ Thousands, unless otherwise noted)	Three months ended June 30, 2020	Three months ended June 30, 2019	Six months ended June 30, 2020	Six months ended June 30, 2019
CONSOLIDATED				
Petroleum and natural gas production (boe/d)	27,067	33,958	31,812	36,568
Operating Income (Loss)[(1)(2)]	$ 6,166	$ 67,122	$ 7,264	$ 125,724
Operating Netback[(1)(2)] ($/boe)	$ 2.37	$ 22.19	$ 1.21	$ 19.29
Capital expenditures	$ 5,811	$ 33,717	$ 82,057	$ 86,681
Capital Expenditures Net of Capital-Carry[(1)]	$ 5,811	$ 26,888	$ 59,317	$ 58,644
LIGHT OIL DIVISION				
Petroleum and natural gas production (boe/d)	9,466	10,210	8,854	10,957
Percentage liquids (%)	62%	51%	61%	52%
Operating Income (Loss)[(1)]	$ 6,350	$ 25,637	$ 19,133	$ 56,917
Operating Netback[(1)] ($/boe)	$ 7.37	$ 27.59	$ 11.88	$ 28.70
Capital expenditures	$ 1,089	$ 11,858	$ 59,617	$ 41,713
Capital Expenditures Net of Capital-Carry[(1)]	$ 1,089	$ 5,029	$ 36,877	$ 13,676
THERMAL OIL DIVISION				
Bitumen production (bbl/d)	17,601	23,748	22,958	25,611
Operating Income (Loss)[(1)]	$ (24,619)	$ 56,522	$ (57,730)	$ 101,650
Operating Netback[(1)] ($/bbl)	$ (14.21)	$ 26.97	$ (13.17)	$ 22.42
Capital expenditures	$ 4,722	$ 21,859	$ 22,418	$ 44,968
CASH FLOW AND FUNDS FLOW				
Cash flow from operating activities	$ (31,186)	$ 61,488	$ (34,207)	$ 42,916
per share - basic	$ (0.06)	$ 0.12	$ (0.06)	$ 0.08
Adjusted Funds Flow[(1)]	$ (16,214)	$ 47,757	$ (44,097)	$ 89,376
per share - basic	$ (0.03)	$ 0.09	$ (0.08)	$ 0.17
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)				
Net income (loss) and comprehensive income (loss)	$ (65,335)	$ 57,091	$ (581,816)	$ 263,887
per share - basic	$ (0.12)	$ 0.11	$ (1.10)	$ 0.51
per share - diluted	$ (0.12)	$ 0.11	$ (1.10)	$ 0.50
COMMON SHARES OUTSTANDING				
Weighted average shares outstanding - basic	530,363,434	522,459,443	526,979,706	519,253,275
Weighted average shares outstanding - diluted	530,363,434	527,661,455	526,979,706	525,417,016

As at ($ Thousands)	June 30, 2020	December 31, 2019
LIQUIDITY AND BALANCE SHEET		
Cash and cash equivalents	$ 167,442	$ 254,389
Restricted cash (current and long-term)	$ 152,125	$ 110,609
Available credit facilities[(3)]	$ 2,560	$ 85,815
Capital-carry receivable (undiscounted)	$ —	$ 22,740
Face value of long-term debt[(4)]	$ 613,260	$ 583,425

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

(2) Includes realized commodity risk management gains of $24.4 million and $45.9 million for the three and six months ended June 30, 2020, respectively (three and six months ended June 30, 2019 - $15.0 million loss and $32.8 million loss).

(3) Includes available credit under Athabasca's Credit Facility and Unsecured Letter of Credit Facility (see page 14).

(4) The face value of the 2022 Notes is US$450 million. The 2022 Notes were translated into Canadian dollars at the June 30, 2020 exchange rate of US$1.00 = C$1.3628.

BUSINESS ENVIRONMENT AND THE IMPACT OF COVID-19

Benchmark prices

(Average)	Three months ended June 30, 2020	2019	Change	Six months ended June 30, 2020	2019	Change
Crude oil:						
West Texas Intermediate (WTI) (US$/bbl)[1]	$ 27.85	$ 59.82	(53) %	$ 37.01	$ 57.36	(35) %
West Texas Intermediate (WTI) (C$/bbl)[1]	$ 38.59	$ 80.11	(52) %	$ 50.49	$ 76.53	(34) %
Western Canadian Select (WCS) (C$/bbl)[2]	$ 22.41	$ 65.73	(66) %	$ 28.26	$ 61.18	(54) %
Edmonton Par (C$/bbl)[3]	$ 29.55	$ 73.60	(60) %	$ 40.58	$ 70.00	(42) %
Edmonton Condensate (C5+) (C$/bbl)[4]	$ 29.95	$ 74.46	(60) %	$ 45.17	$ 70.53	(36) %
WCS Differential:						
to WTI (US$/bbl)	$ (11.47)	$ (10.67)	7 %	$ (16.00)	$ (11.48)	39 %
to WTI (C$/bbl)	$ (16.18)	$ (14.38)	13 %	$ (22.23)	$ (15.35)	45 %
Edmonton Par Differential:						
to WTI (US$/bbl)	$ (6.14)	$ (4.62)	33 %	$ (6.86)	$ (4.73)	45 %
to WTI (C$/bbl)	$ (9.04)	$ (6.51)	39 %	$ (9.91)	$ (6.53)	52 %
Natural gas:						
AECO (C$/GJ)[5][6]	$ 1.89	$ 0.98	93 %	$ 1.91	$ 1.73	10 %
Chicago Citygate (US$/MMBtu)[6]	$ 1.61	$ 2.31	(30) %	$ 1.68	$ 2.56	(34) %
Foreign exchange:						
USD : CAD	1.3856	1.3393	3 %	1.3643	1.3342	2 %

Primary benchmark for:
(1) Crude oil pricing in North America.
(2) Athabasca's blended bitumen sales.
(3) Crude oil sales in the Company's Light Oil Division.
(4) 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 sales in the Company's Light Oil Division.

In March 2020, the COVID-19 outbreak was declared a pandemic by the World Health Organization. Global commodity prices declined significantly as countries around the world enacted emergency measures to combat the spread of the virus. The decrease in oil demand has been unprecedented with an estimated peak demand impact of 20 MMbbl/d in April 2020 (Goldman Sachs Global Investment Research). Since April, global demand has improved while OPEC and North American producers have cut production. Global inventories have begun to moderate with economies reopening and leading to a partial recovery and stabilization in oil prices.

In Alberta, physical markets and regional benchmark prices (e.g. Western Canadian Select “WCS” heavy oil) have materially strengthened with WTI prices and tighter differentials as a result of curtailed volumes. Athabasca expects WCS differentials to widen from current spot levels (US$7.79/bbl August WCS index differentials) through the fall as more industry volumes are placed back on production.

The global heavy oil market continues to see structural supply declines in Venezuela and Mexico, extended OPEC production cuts and growing petrochemical demand. These shifting dynamics are expected to support heavy oil pricing benchmarks with US refineries in PADD II and III requiring a heavier feedstock. Athabasca is well positioned for this changing dynamic with its Thermal Oil assets.

OUTLOOK AND RESPONSE TO COVID-19

Safety is a key priority for Athabasca. The Company has implemented business procedures that comply with Alberta Health Guidelines. Athabasca has successfully transitioned its office staff back to the office and the field sites continue to take site specific pre-cautionary measures related to COVID-19. The Company has not experienced any COVID-19 cases in the Calgary office or at its field sites.

The Company has taken swift action in response to the pandemic and economic crisis. Major initiatives to date include a reduction to the 2020 capital program, significant production curtailments, partnering with service companies to reduce operating costs and reducing future financial commitments on the Keystone XL pipeline. Finally, the Company bolstered its liquidity by $70 million through an upsized Contingent Bitumen Royalty.

Athabasca reiterates its $85 million 2020 capital budget, a $40 million reduction from the original budget. Athabasca has minimal capital activity planned for the balance of the year, including approximately $25 million for the second half of 2020 for only routine pump-changes on Thermal Oil wells (no additional Light Oil activity is planned for the balance of the year).

The Company forecasts fourth quarter 2020 production between 32,000 – 34,000 boe/d (approximately 88% liquids) reflecting a ramp-up in volumes following curtailments and the Hangingstone suspension.

At Leismer, volumes were curtailed down to 15,000 bbl/d in late April. As the commodity outlook improved the Company commenced ramping up volumes through the balance of the quarter. July production is expected to average approximately 18,500 bbl/d. Leismer operations are now benefiting from the water disposal project which was completed in the first quarter of 2020. The project is estimated to reduce non-energy operating costs by approximately $10 million on an annual basis. In addition, Leismer's steam oil ratio ("SOR") is currently 3.4x supported by the ramp-up of sustaining Pad L7 and non-condensable gas co-injection on the mature pads. These activities have reduced field wide steam demand by 15 percent relative to the prior year and is supporting lower energy operating costs and emissions.

At Hangingstone, operations were suspended in April 2020. Through the summer planned Hangingstone turnaround activities were completed. With the improved commodity price outlook, the Company is planning to restart Hangingstone's field operations in September. To protect against future commodity price volatility the Company has hedged the Hangingstone production profile through next winter and intends to secure additional risk management activities for the balance of 2021. The Company has utilized a collar hedge structure with a minimum WCS floor price of approximately US$25/bbl with upside potential to approximately US$31/bbl WCS (Q4 2020 – Q1 2021).

The Company is well positioned to navigate the current challenging environment with $170 million in liquidity, of which $167 million is unrestricted cash. The Company's Reserve Based Lending ("RBL") credit facility was renewed at $41 million which reflects the current outstanding letters of credit for long term transportation commitments and is secured by the Company's cash balances. Athabasca is currently pursuing additional financial support under the previously announced EDC RBL support program. Athabasca is disappointed in the lack of urgency by the Federal Government to administer the program in an effective manner.

Athabasca remains focused on maximizing corporate funds flow and maintaining strong 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. The low decline nature of the Company's assets allows for minimal capital investment while maintaining its production base for a crude oil demand recovery.

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 June 30, 2020	2019	Six months ended June 30, 2020	2019
PRODUCTION				
Oil and condensate (bbl/d)	5,142	4,336	4,665	4,761
Natural gas (Mcf/d)	21,863	30,005	20,962	31,284
Natural gas liquids (bbl/d)	680	873	695	982
Bitumen (bbl/d)	17,601	23,748	22,958	25,611
Total (boe/d)	27,067	33,958	31,812	36,568

($ Thousands, unless otherwise noted)	Three months ended June 30, 2020	2019	Six months ended June 30, 2020	2019
Petroleum and natural gas sales[1]	$ 56,037	$ 224,531	$ 194,537	$ 450,658
Royalties	(1,010)	(4,769)	(2,929)	(8,674)
Cost of diluent[1][2]	(32,598)	(71,214)	(118,530)	(149,757)
Operating expenses[2]	(22,978)	(41,532)	(68,808)	(85,091)
Transportation and marketing[2]	(17,720)	(24,857)	(42,867)	(48,569)
	$ (18,269)	$ 82,159	$ (38,597)	$ 158,567
Realized gain (loss) on commodity risk management contracts	24,435	(15,037)	45,861	(32,843)
Consolidated Operating Income (Loss)[2]	$ 6,166	$ 67,122	$ 7,264	$ 125,724
REALIZED PRICES				
Oil and condensate ($/bbl)	$ 25.08	$ 72.07	$ 37.10	$ 67.78
Natural gas ($/Mcf)	2.09	2.20	2.06	2.82
Natural gas liquids ($/bbl)	14.83	30.09	14.01	35.13
Blended bitumen sales ($/bbl)	16.02	63.56	24.45	57.25
Realized price (net of cost of diluent) ($/boe)	9.03	50.69	12.68	46.17
Royalties ($/boe)	(0.39)	(1.58)	(0.49)	(1.33)
Operating expenses ($/boe)	(8.86)	(13.73)	(11.48)	(13.06)
Transportation and marketing ($/boe)	(6.83)	(8.22)	(7.15)	(7.45)
	$ (7.05)	$ 27.16	$ (6.44)	$ 24.33
Realized gain (loss) on commodity risk mgmt. contracts ($/boe)	9.42	(4.97)	7.65	(5.04)
CONSOLIDATED OPERATING NETBACK[2] ($/boe)	$ 2.37	$ 22.19	$ 1.21	$ 19.29

(1) Includes intercompany 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.

Consolidated Segments Income (Loss)

($ Thousands)	Three months ended June 30, 2020	2019	Six months ended June 30, 2020	2019
Consolidated Operating Income (Loss)[1]	$ 6,166	$ 67,122	$ 7,264	$ 125,724
Inventory write-down impact[1]	15,464	—	—	—
Unrealized gain (loss) on commodity risk management contracts	(52,841)	33,634	15,270	9,649
Impairment loss	—	—	(471,839)	—
Depletion and depreciation	(24,585)	(31,508)	(55,030)	(65,983)
Gain (loss) on sale of assets	21,008	449	21,202	222,055
Exploration and non-producing asset expenses	(11,855)	(171)	(12,125)	(797)
CONSOLIDATED SEGMENTS INCOME (LOSS)	$ (46,643)	$ 69,526	$ (495,258)	$ 290,648

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

Consolidated Capital Expenditures

($ Thousands)		Three months ended June 30, 2020		2019		Six months ended June 30, 2020		2019
Light Oil Division	$	1,089	$	11,858	$	59,617	$	41,713
Thermal Oil Division		4,722		21,859		22,418		44,968
Corporate assets		—		—		22		—
TOTAL CAPITAL EXPENDITURES(1)	$	5,811	$	33,717	$	82,057	$	86,681
Less: Greater Kaybob capital-carry		—		(6,829)		(22,740)		(28,037)
TOTAL CAPITAL EXPENDITURES NET OF CAPITAL-CARRY(2)	$	5,811	$	26,888	$	59,317	$	58,644

(1) For the three and six months ended June 30, 2020, capital expenditures include $1.0 million and $3.3 million of capitalized cash staff costs, respectively (three and six months ended June 30, 2019 - $2.2 million and $4.4 million).

(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, 2019, the Light Oil Division had approximately 72 MMboe of Proved plus Probable Reserves(1). Athabasca's Light Oil Division assets are supported by operated regional infrastructure primarily consisting of four batteries and a network of gas pipelines which connect the facilities to two regional third party gas processing plants.

In Greater Placid, Athabasca has a 70% operated working interest in approximately 80,000 gross Montney acres. Athabasca has transitioned Greater Placid from early stage resource capture to efficient multi-well pad development. An inventory of approximately 200(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. 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, 2019. Refer to the "Advisories and Other Guidance" section within this MD&A and the AIF for additional information about the Company's reserves and resources.

(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information regarding the Company's drilling locations.

Light Oil Operating Results

	Three months ended June 30, 2020	2019	Six months ended June 30, 2020	2019
PRODUCTION				
Oil and condensate (bbl/d)	5,142	4,336	4,665	4,761
Natural gas (Mcf/d)	21,863	30,005	20,962	31,284
Natural gas liquids (bbl/d)	680	873	695	982
Total (boe/d)	9,466	10,210	8,854	10,957
Consisting of:				
Greater Placid area (boe/d)	4,675	6,081	4,331	6,540
% liquids	49%	44%	48%	45%
Greater Kaybob area (boe/d)	4,791	4,129	4,523	4,417
% liquids	73%	61%	72%	63%

($ Thousands, unless otherwise noted)	Three months ended June 30, 2020	2019	Six months ended June 30, 2020	2019
Petroleum and natural gas sales	$ 16,806	$ 36,836	$ 41,153	$ 80,614
Royalties	(844)	(603)	(1,828)	(2,498)
Operating expenses	(5,472)	(5,320)	(12,463)	(11,131)
Transportation and marketing	(4,140)	(5,276)	(7,729)	(10,068)
Light Oil Operating Income (Loss)(1)	$ 6,350	$ 25,637	$ 19,133	$ 56,917
REALIZED PRICES				
Oil and condensate ($/bbl)	$ 25.08	$ 72.07	$ 37.10	$ 67.78
Natural gas ($/Mcf)	2.09	2.20	2.06	2.82
Natural gas liquids ($/bbl)	14.83	30.09	14.01	35.13
Realized price ($/boe)	19.51	39.65	25.54	40.65
Royalties ($/boe)	(0.98)	(0.65)	(1.13)	(1.26)
Operating expenses ($/boe)	(6.35)	(5.73)	(7.73)	(5.61)
Transportation and marketing ($/boe)	(4.81)	(5.68)	(4.80)	(5.08)
LIGHT OIL OPERATING NETBACK(1) ($/boe)	$ 7.37	$ 27.59	$ 11.88	$ 28.70

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

Athabasca's Light Oil production averaged 9,466 boe/d and 8,854 boe/d during the three and six months ended June 30, 2020, decreases of 7% and 19%, respectively, from the comparable 2019 periods. Production decreases were primarily the result of natural declines at Greater Placid on the legacy wells and a deferred start-up of the 10 (gross) new Montney development wells until July due to low commodity prices. The 10 (gross) Montney wells were placed back on production in July and are expected to support volumes through the balance of 2020. Activity in the Greater Kaybob Duvernay has been focused on completing resource de-risking and land retention during the initial five year joint venture appraisal period.

Athabasca's Light Oil Operating Netback's decreased from the comparable periods in 2019 primarily due to lower liquids benchmark commodity prices.

Athabasca generated Light Oil Operating Income of $6.4 million in the second quarter of 2020 and $19.1 in the first six months of 2020, decreases of 75% and 66% over the comparable 2019 periods. The decrease in petroleum and natural gas sales was driven primarily by lower production and lower liquids benchmark prices.

Light Oil Segment Income (Loss)

($ Thousands)	Three months ended June 30, 2020	2019	Six months ended June 30, 2020	2019
Light Oil Operating Income (Loss)[1]	$ 6,350	$ 25,637	$ 19,133	$ 56,917
Impairment loss	—	—	(263,955)	—
Depletion and depreciation	(14,814)	(17,676)	(30,140)	(37,592)
Gain (loss) on sale of assets	—	—	—	(1,205)
LIGHT OIL SEGMENT INCOME (LOSS)	$ (8,464)	$ 7,961	$ (274,962)	$ 18,120

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

Athabasca previously recognized a Light Oil impairment of $264.0 million in the first quarter of 2020 as a result of the recent market volatility and lower commodity price forecasts.

Depletion and depreciation decreased in 2020 compared to the same periods in the prior year, primarily due to the March 31, 2020 impairment and due to lower production volumes in 2020.

Light Oil Capital Expenditures

($ Thousands)	Three months ended June 30, 2020	2019	Six months ended June 30, 2020	2019
Greater Placid	$ —	$ 2,671	$ 21,714	$ 4,072
Greater Kaybob	1,089	9,187	37,903	37,641
TOTAL LIGHT OIL CAPITAL EXPENDITURES[1]	$ 1,089	$ 11,858	$ 59,617	$ 41,713
Less: Greater Kaybob capital-carry	—	(6,829)	(22,740)	(28,037)
TOTAL CAPITAL EXPENDITURES NET OF CAPITAL-CARRY[2]	$ 1,089	$ 5,029	$ 36,877	$ 13,676

(1) For the three and six months ended June 30, 2020, capital expenditures include $0.5 million and $1.5 million of capitalized cash staff costs, respectively (three and six months ended June 30, 2019 - $1.0 million and $2.0 million, respectively).

(2) 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 $1.1 million and $15.2 million for the three and six months ended June 30, 2020, respectively (three and six months ended June 30, 2019 - $2.4 million and $9.6 million).

In the first six months of 2020, Light Oil capital expenditures of $59.6 million were primarily incurred for drilling and completions in the first quarter. The following table summarizes Athabasca's well activity for the three and six months ended June 30, 2020 and 2019:

	Three months ended June 30, 2020		2019		Six months ended June 30, 2020		2019	
Well activity[1]	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Greater Placid								
Wells drilled	—	—	—	—	—	—	—	—
Wells completed	—	—	—	—	7	4.9	—	—
Wells brought on production	6	4.2	—	—	10	7.0	—	—
Greater Kaybob								
Wells drilled	—	—	—	—	8	2.4	6	1.8
Wells completed	—	—	2	0.6	13	3.7	10	3.0
Wells brought on production	2	0.5	4	1.2	13	3.8	8	2.4

(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 Athabasca's low corporate production decline and low 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 695 MMbbl(1) and 319 MMbbl (risked)(1) (354 MMbbl unrisked)(1) of Best Estimate Development Pending Contingent Resources. The Corner lease has Proved plus Probable Reserves of approximately 353 MMbbl(1) and 416 MMbbl (risked)(1) (520 MMbbl unrisked)(1) of Best Estimate Development Pending Contingent Resources. 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 177 MMbbl(1). 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 COVID-19 crisis. This suspension involved shutting in the well pairs, halting steam injection to the reservoir, and measures were taken to preserve the processing facility and pipelines in a safe manner so that it could be re-started at a future date. Athabasca has completed the planned maintenance activities related to the 2020 turnaround with the intention of restarting the facility in September.

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

Athabasca's Thermal Oil Division has access to multiple sales points with marketing agreements on the Enbridge Waupisoo transportation pipeline. In the third quarter of 2019, the Company secured approximately 7,200 bbl/d of blended bitumen capacity on the existing Keystone pipeline diversifying its end market access to the US Gulf Coast which is expected to be available in the first quarter of 2021. The Company has secured 8,000 bbl/d of direct refinery sales for 2020 which mitigates apportionment risk on the Enbridge Mainline. 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 follows the same structure as the existing contingent bitumen royalties and 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 (was US$140 WCS). On the greenfield assets (Dover West, Birch and Grosmont) the Royalty structure is unchanged and 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, 2019. Refer to the "Advisories and Other Guidance" section within this MD&A and the AIF for additional information about the Company's reserves and resources.

Leismer Operating Results

	Three months ended June 30, 2020	2019	Six months ended June 30, 2020	2019
VOLUMES				
Bitumen production (bbl/d)	17,433	15,968	18,626	17,197
Bitumen sales (bbl/d)	17,260	15,788	18,552	16,994
Blended bitumen sales (bbl/d)	24,197	21,841	26,269	23,818

($ Thousands, unless otherwise noted)	Three months ended June 30, 2020	2019	Six months ended June 30, 2020	2019
Blended bitumen sales	$ 38,158	$ 126,944	$ 115,208	$ 246,260
Cost of diluent(1)	(27,284)	(45,240)	(83,210)	(95,418)
Total bitumen sales	10,874	81,704	31,998	150,842
Royalties	(166)	(3,041)	(914)	(4,415)
Operating expenses - non-energy(1)	(7,842)	(18,339)	(23,576)	(31,173)
Operating expenses - energy	(6,655)	(5,175)	(15,090)	(14,582)
Transportation and marketing(1)	(10,716)	(10,512)	(21,829)	(20,023)
Leismer Operating Income (Loss)(1)	$ (14,505)	$ 44,637	$ (29,411)	$ 80,649
REALIZED PRICE				
Blended bitumen sales ($/bbl)	$ 17.33	$ 63.87	$ 24.10	$ 57.12
Bitumen sales ($/bbl)	$ 6.92	$ 56.87	$ 9.48	$ 49.04
Royalties ($/bbl)	(0.11)	(2.12)	(0.27)	(1.44)
Operating expenses - non-energy ($/bbl)	(4.99)	(12.76)	(6.98)	(10.13)
Operating expenses - energy ($/bbl)	(4.24)	(3.60)	(4.47)	(4.74)
Transportation and marketing ($/bbl)	(6.82)	(7.32)	(6.47)	(6.51)
LEISMER OPERATING NETBACK(1) ($/bbl)	$ (9.24)	$ 31.07	$ (8.71)	$ 26.22

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

Leismer production in the second quarter and first half of 2020 was 9% and 8% higher, respectively, than the comparable periods in 2019. The higher production was primarily due to the ramp up of the new sustaining pad (Pad 7) and minimal maintenance activity compared to 2019. Both years were impacted by pricing related curtailments. In April 2020, Leismer was initially curtailed down to 15,000 bbl/d but with the recovery in oil prices it was ramped back up and has since recovered to approximately 18,500 bbl/d in July 2020.

The Leismer Operating Netback's in 2020 were lower than 2019 primarily driven by lower benchmark oil prices.

Total operating expenses were $9.23/bbl in the second quarter of 2020 and $11.45/bbl in the first six months of 2020, compared to $16.36/bbl and $14.87/bbl in the comparable periods of 2019. Non-energy costs per bbl in the first six months of 2020 decreased relative to the prior year primarily due to the completion of the disposal well project at the end of the first quarter of 2020 and the impact of several cost optimization initiatives in 2020. Energy operating costs per barrel in the second quarter of 2020 were higher relative to the prior year primarily due to higher gas prices offset by improvements in the Steam Oil Ratio ("SOR") due to increased co-injection of non-condensable gas and the impact of Pad 7's low 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 June 30, 2020	2019	Six months ended June 30, 2020	2019
VOLUMES				
Bitumen production (bbl/d)	168	7,780	4,332	8,414
Bitumen sales (bbl/d)	1,785	7,240	5,520	8,059
Blended bitumen sales (bbl/d)	2,708	10,611	8,206	11,890

($ Thousands, unless otherwise noted)	Three months ended June 30, 2020	2019	Six months ended June 30, 2020	2019
Blended bitumen sales	$ 1,073	$ 60,751	$ 38,176	$ 123,784
Cost of diluent[1]	(5,314)	(25,974)	(35,320)	(54,339)
Total bitumen sales	(4,241)	34,777	2,856	69,445
Royalties	—	(1,125)	(187)	(1,761)
Operating expenses - non-energy[1]	(1,426)	(8,908)	(9,668)	(17,795)
Operating expenses - energy	(1,583)	(3,790)	(8,011)	(10,410)
Transportation and marketing[1]	(2,864)	(9,069)	(13,309)	(18,478)
Hangingstone Operating Income (Loss)[1]	$ (10,114)	$ 11,885	$ (28,319)	$ 21,001
REALIZED PRICE				
Blended bitumen sales ($/bbl)	$ 4.35	$ 62.92	$ 25.56	$ 57.52
Bitumen sales ($/bbl)	$ (26.11)	$ 52.79	$ 2.84	$ 47.61
Royalties ($/bbl)	—	(1.71)	(0.19)	(1.21)
Operating expenses - non-energy ($/bbl)	(8.78)	(13.52)	(9.62)	(12.20)
Operating expenses - energy ($/bbl)	(9.75)	(5.75)	(7.97)	(7.14)
Transportation and marketing ($/bbl)	(17.63)	(13.77)	(13.25)	(12.67)
HANGINGSTONE OPERATING NETBACK[1] ($/bbl)	$ (62.27)	$ 18.04	$ (28.19)	$ 14.39

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

Due to the significant decline in oil prices combined with the economic uncertainty associated to the COVID pandemic, Athabasca suspended the Hangingstone SAGD operation. The asset was self-curtailed by approximately 50% on March 20, 2020 and the complete suspension was initiated on April 2, 2020. The suspension involved shutting in the well pairs, halting steam injection to the reservoir, and measures were taken to preserve the processing facility and pipelines in a safe manner so that it could be re-started at a future date.

Athabasca has completed the planned maintenance activities related to the 2020 turnaround with the intention of restarting the facility in September.

Consolidated Thermal Oil Operating Results

	Three months ended June 30, 2020	2019	Six months ended June 30, 2020	2019
VOLUMES				
Bitumen production (bbl/d)	17,601	23,748	22,958	25,611
Bitumen sales (bbl/d)	19,045	23,028	24,072	25,053
Blended bitumen sales (bbl/d)	26,905	32,452	34,475	35,708

($ Thousands, unless otherwise noted)	Three months ended June 30, 2020	2019	Six months ended June 30, 2020	2019
Blended bitumen sales	$ 39,231	$ 187,695	$ 153,384	$ 370,044
Cost of diluent[(1)]	(32,598)	(71,214)	(118,530)	(149,757)
Total bitumen sales	6,633	116,481	34,854	220,287
Royalties	(166)	(4,166)	(1,101)	(6,176)
Operating expenses - non-energy[(1)]	(9,268)	(27,247)	(33,244)	(48,968)
Operating expenses - energy	(8,238)	(8,965)	(23,101)	(24,992)
Transportation and marketing[(1)]	(13,580)	(19,581)	(35,138)	(38,501)
Thermal Oil Operating Income (Loss)[(1)]	$ (24,619)	$ 56,522	$ (57,730)	$ 101,650
REALIZED PRICE				
Blended bitumen sales ($/bbl)	$ 16.02	$ 63.56	$ 24.45	$ 57.25
Bitumen sales ($/bbl)	$ 3.83	$ 55.58	$ 7.96	$ 48.58
Royalties ($/bbl)	(0.10)	(1.99)	(0.25)	(1.36)
Operating expenses - non-energy ($/bbl)	(5.35)	(13.00)	(7.59)	(10.80)
Operating expenses - energy ($/bbl)	(4.75)	(4.28)	(5.27)	(5.51)
Transportation and marketing ($/bbl)	(7.84)	(9.34)	(8.02)	(8.49)
THERMAL OIL OPERATING NETBACK[(1)] ($/bbl)	$ (14.21)	$ 26.97	$ (13.17)	$ 22.42

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

Thermal Oil Segment Income (Loss)

($ Thousands)	Three months ended June 30, 2020	2019	Six months ended June 30, 2020	2019
Thermal Oil Operating Income (Loss)[(1)]	$ (24,619)	$ 56,522	$ (57,730)	$ 101,650
Inventory write-down impact[(1)]	15,464	—	—	—
Impairment loss	—	—	(207,884)	—
Depletion and depreciation	(9,771)	(13,832)	(24,890)	(28,391)
Gain (loss) on sale of assets	21,008	449	21,202	223,260
Exploration and non-producing asset expenses	(11,855)	(171)	(12,125)	(797)
THERMAL OIL SEGMENT INCOME (LOSS)	$ (9,773)	$ 42,968	$ (281,427)	$ 295,722

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

Athabasca previously recognized an impairment loss of $207.9 million in its first quarter of 2020 as it fully impaired the Hangingstone Cash Generating Unit ("CGU") due to 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 after the suspension and 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 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 Leismer Infrastructure Transaction.

Thermal Oil Capital Expenditures

($ Thousands)	Three months ended June 30, 2020	2019	Six months ended June 30, 2020	2019
Leismer Project	$ 4,669	$ 19,697	$ 20,927	$ 41,674
Hangingstone Project	—	2,128	1,342	3,187
Other Thermal Oil exploration	53	34	149	107
TOTAL THERMAL OIL CAPITAL EXPENDITURES(1)	$ 4,722	$ 21,859	$ 22,418	$ 44,968

(1) For the three and six months ended June 30, 2020, capital expenditures include $0.5 million and $1.8 million of capitalized staff costs (three and six months ended June 30, 2019 - $1.2 million and $2.4 million).

Thermal Oil capital expenditures for the first half of 2020 of $22.4 million were primarily associated with Leismer including the completion of the water disposal project, long-lead items and the drilling of four observation wells for Pad 8.

CORPORATE REVIEW

Liquidity and Capital Resources

Funding

Balance sheet strength and flexibility is a key priority for Athabasca and the Company's objectives in managing capital are ensuring 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 June 30, 2020, Athabasca had liquidity of $170.0 million, including $167.4 million of unrestricted cash and cash equivalents, and $2.6 million of available credit under its Unsecured Letter of Credit Facility (defined below).

For the balance of 2020, it is anticipated that Athabasca's Light Oil and Thermal Oil capital and operating activities will be funded through cash flow from operating activities, existing cash and cash equivalents and available credit facilities. Beyond 2020, depending on the Company's level of capital spend and the commodity price environment, the Company 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)	June 30, 2020	December 31, 2019
2022 Notes(1)	$ 613,260	$ 583,425
Debt issuance costs	(47,081)	(47,081)
Amortization of debt issuance costs	28,309	23,343
TOTAL LONG-TERM DEBT	$ 594,488	$ 559,687

(1) As at June 30, 2020, the US dollar denominated 2022 Notes were translated into Canadian dollars at the period end exchange rate of US$1.00 = C$1.3628.

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

- February 24, 2020 to February 23, 2021 - 102.5% of principal
- February 24, 2021 to maturity - 100% of principal

Credit Facility

In the second quarter of 2020, the Company's banking syndicate has renewed the reserve-based credit facility (the "Credit Facility") until November 30, 2020. The credit facility has been reduced to $40.7 million which reflects the currently outstanding letters of credit for transportation commitments. If the revolving period is not extended in November 2020 any outstanding letters of credit would be cancelled at the end of the non-revolving term, being May 31, 2021. The borrowing base is determined based on the lender's evaluation of the Company's petroleum and natural gas reserves and their commodity price outlook at the time of each renewal.

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 June 30, 2020, $41.1 million of restricted cash was held in the cash-collateral account (December 31, 2019 - $nil) of which $31.2 million was current and $9.9 million included in non-current restricted cash. 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.

As at June 30, 2020, the Company had no amounts drawn and had $40.7 million letters of credit issued under the Credit Facility which bear interest at 0.5%. 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.

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 June 30, 2020, Athabasca had $109.7 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 June 30, 2020, $111.0 million of restricted cash was held in the cash-collateral account (December 31, 2019 - $110.6 million) all of which is included in non-current restricted cash.

Unsecured Letter of Credit Facility

Athabasca maintains a $30.0 million unsecured letter of credit facility (the "Unsecured Letter of Credit Facility") with a Canadian bank which 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 2.7%. As at June 30, 2020, the Company had $27.4 million of letters of credit issued and drawn under the Unsecured Letter of Credit Facility (December 31, 2019 - $24.8 million).

Financing and Interest

	Three months ended June 30,		Six months ended June 30,	
($ Thousands)	2020	2019	2020	2019
Financing and interest expense on indebtedness	$ 15,989	$ 15,252	$ 31,728	$ 30,447
Amortization of debt issuance costs	2,887	2,253	5,369	4,493
Accretion of provisions	3,097	2,853	6,035	5,699
Interest expense on lease liability	378	439	772	892
TOTAL FINANCING AND INTEREST	$ 22,351	$ 20,797	$ 43,904	$ 41,531

During the three and six months ended June 30, 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 June 30, 2020	2019	Six months ended June 30, 2020	2019
Unrealized foreign exchange gain (loss)	$ 24,305	$ 12,105	$ (28,180)	$ 24,975
Realized foreign exchange gain (loss)	(4,486)	(27)	2,210	713
FOREIGN EXCHANGE GAIN (LOSS), NET	$ 19,819	$ 12,078	$ (25,970)	$ 25,688

Athabasca is exposed to foreign currency risk primarily on the principal and interest components of its US dollar denominated 2022 Notes. 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.

Athabasca is also exposed to foreign exchange risk on the principal and interest components of its US dollar denominated 2022 Notes and may utilize financial contracts to reduce its exposure to foreign currency risk. As at June 30, 2020, no foreign exchange risk management contracts were in place.

Financial commodity risk management contracts

As at June 30, 2020, the following financial commodity risk management contracts were in place:

Instrument	Period	Volume	C$ Average Price/bbl[1]	US$ Average Price/bbl[1]
Sales contracts				
WTI fixed price swaps	July - September 2020	3,000 bbl/d	$ 74.99	$ 55.03
WTI/WCS differential swaps	July - September 2020	16,000 bbl/d	$ (24.23)	$ (17.78)
WTI three way collar	July - September 2020	6,000 bbl/d	$ 67.57|76.09|82.90	$ 49.58|55.83|60.83
WTI fixed price swaps	October - December 2020	3,000 bbl/d	$ 74.99	$ 55.03
WTI/WCS differential swaps	October - December 2020	11,000 bbl/d	$ (25.38)	$ (18.62)
WTI three way collar	October - December 2020	6,000 bbl/d	$ 67.57|76.09|82.90	$ 49.58|55.83|60.83
Purchase contracts				
C5+ fixed price swaps	October - December 2020	1,000 bbl/d	$ 55.87	$ 41.00

(1) The implied C$ or US$ Average Price/bbl, as applicable, was calculated using the June 30, 2020 exchange rate of US$1.00 = C$1.3628.

The following table summarizes the Company's net gain (loss) on commodity risk management contracts for the three and six months ended June 30, 2020 and 2019:

($ Thousands)	Three months ended June 30, 2020	2019	Six months ended June 30, 2020	2019
Unrealized gain (loss) on commodity risk mgmt. contracts	$ (52,841)	$ 33,634	$ 15,270	$ 9,649
Realized gain (loss) on commodity risk mgmt. contracts	24,435	(15,037)	45,861	(32,843)
GAIN (LOSS) ON COMMODITY RISK MGMT. CONTRACTS, NET	$ (28,406)	$ 18,597	$ 61,131	$ (23,194)

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

As at June 30, 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	$ (3,134)	$ 3,134	$ 3,286	$ (3,286)

Additional financial commodity risk management activity related to 2020 and 2021 has taken place subsequent to June 30, 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	October - December 2020	8,900 bbl/d	$ (20.20)	$ (14.82)
WTI costless collar	October - December 2020	8,900 bbl/d	$ 54.27- 62.15	$ 39.82 - 45.61
WTI/WCS differential swaps	January - March 2021	11,000 bbl/d	$ (20.13)	$ (14.77)
WTI costless collar	January - March 2021	11,000 bbl/d	$ 54.38 - 62.19	$ 39.90 - 45.63
WTI call options(2)	April - June 2021	8,900 bbl/d	$ 74.95	$ 55.00
WTI call options(2)	July - September 2021	8,900 bbl/d	$ 74.95	$ 55.00
WTI call options(2)	October - December 2021	8,900 bbl/d	$ 74.95	$ 55.00

(1) The implied C$ or US$ Average Price/bbl, as applicable, was calculated using the June 30, 2020 exchange rate of US$1.00 = C$1.3628.
(2) These WTI call options were sold to a counterparty in order to enter into the October 2020 to March 2021 WTI costless collars at the price detailed in the above table.

Commitments and Contingencies

The following table summarizes Athabasca's estimated future unrecognized minimum commitments as at June 30, 2020 for the following five years and thereafter:

($ Thousands)	Remaining 2020	2021	2022	2023	2024	Thereafter	Total
Transportation and processing(1)	$ 59,035	$ 132,067	$ 128,576	$ 184,487	$ 195,843	$3,221,738	$3,921,746
Interest expense on long-term debt(1)	9,084	60,559	30,280	—	—	—	99,923
Purchase commitments	9,462	4,649	—	—	—	—	14,111
TOTAL COMMITMENTS	$ 77,581	$ 197,275	$ 158,856	$ 184,487	$ 195,843	$3,221,738	$4,035,780

(1) Commitments which are denominated in US dollars were translated into Canadian dollars at the June 30, 2020 exchange rate of US$1.00 = C$1.3628.

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 entered into a 20 year firm service transportation agreement for approximately 7,200 bbl/d of blended bitumen capacity on the existing Keystone pipeline and a development cost agreement in relation to the Keystone XL pipeline. This agreement provides for a US$48.0 million ($65.4 million) conditional payment, which is only payable if shipper agreements on the Keystone XL pipeline were terminated on or before January 31, 2020. In connection with such agreements, Athabasca provided $85.6 million in financial assurances, consisting of $34.1 million (US$25 million) of cash and $51.5 million of letters of credit. TC Energy and the Alberta Government announced on March 31, 2020 that the Alberta Government would provide financial support in the form of a $1.5 billion equity investment in 2020 and $6 billion of loan guarantees in 2021, enabling completion of the Keystone XL pipeline. As a result, the project resumed construction on April 1, 2020. The Keystone XL project has clearly not been cancelled however certain regulatory and technical matters have resulted in the extension of shipper agreements to no later than March 31, 2021.

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 were 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 June 30, 2020. Athabasca's risk management contracts are held with four counterparties, all of which were 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 of $319.6 million (December 31, 2019 - $365.0 million), from a 1.0% change in interest rates, would be approximately $3.2 million for a 12 month period (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 June 30, 2020	Three months ended June 30, 2019	Six months ended June 30, 2020	Six months ended June 30, 2019
TOTAL GENERAL AND ADMINISTRATIVE	$ 5,329	$ 5,529	$ 10,726	$ 10,478
G&A per boe	$ 2.16	$ 1.79	$ 1.85	$ 1.58

During the three and six months ended June 30, 2020, Athabasca's G&A expenses were relatively consistent with the same periods in the prior year. G&A per boe increased in the three and six months ended June 30, 2020, compared to the same periods in the prior year, primarily due to the decrease in production year-over-year.

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 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 and six months ended June 30, 2020, Athabasca's stock-based compensation was a $1.4 million and $0.8 million, respectively, compared to $2.6 million and $4.3 million in the respective prior year periods. The decreases are 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, Net

($ Thousands)	Three months ended June 30, 2020	Three months ended June 30, 2019	Six months ended June 30, 2020	Six months ended June 30, 2019
Contingent payment obligation gain (loss)	$ 171	$ 3,205	$ 1,028	$ 1,423
Capital-carry receivable gain (loss)	—	538	138	1,491
Other	(3,700)	(9)	(1,157)	(9)
GAIN (LOSS) ON REVALUATION OF PROVISIONS AND OTHER, NET	$ (3,529)	$ 3,734	$ 9	$ 2,905

The gains or losses on revaluation of the contingent payment obligation are primarily due to fluctuations in forecasted prices for WTI.

Income Taxes

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.

The Company has approximately $3.2 billion in tax pools, including approximately $2.2 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 June 30, 2020, there were 530.7 million common shares outstanding, an aggregate of 26.2 million restricted share units, performance share units and deferred shares units outstanding, 7.1 million stock options outstanding and 8.7 million units outstanding under a new “Phantom Share Unit” plan that were issued in April 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. As at June 30, 2020, Athabasca recognized a PUPs liability within Provisions and other liabilities of $0.2 million which has a current portion of $0.1 million. Refer to the December 31, 2019 audited consolidated financial statements of the Company for further information on the Company’s other stock-based compensation plans. During the three and six months ended June 30, 2020, Athabasca issued 7.0 million and 7.2 million common shares, respectively, in respect of the Company’s equity-settled share-based compensation plans.

SUMMARY OF QUARTERLY RESULTS

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

	2020		2019				2018	
($ Thousands, unless otherwise noted)	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	27.85	46.17	56.96	56.45	59.82	54.90	58.81	69.50
WTI (C$/bbl)	38.59	62.03	75.19	74.56	80.11	72.97	77.70	90.84
Western Canadian Select (C$/bbl)	22.41	34.11	54.27	58.36	65.73	56.62	25.36	61.75
Edmonton Par (C$/bbl)	29.55	51.62	67.99	68.21	73.60	66.41	42.75	81.90
Edmonton Condensate (C5+) (C$/bbl)	29.95	60.39	69.22	68.03	74.46	66.60	59.73	87.01
AECO (C$/GJ)	1.89	1.93	2.35	0.87	0.98	2.49	1.48	1.13
Chicago Citygate (US$/MMBtu)	1.61	1.74	2.20	2.08	2.31	2.82	3.67	2.79
Foreign exchange (USD : CAD)	1.39	1.34	1.32	1.32	1.34	1.33	1.32	1.31
CONSOLIDATED								
Petroleum and natural gas production (boe/d)	27,067	36,557	36,403	35,257	33,958	39,206	37,984	40,612
Realized price (net of cost of diluent) ($/boe)(1)	9.03	15.47	38.61	43.63	50.69	42.25	2.47	43.42
Petroleum and natural gas sales ($)(2)	56,037	138,500	188,101	216,338	224,531	226,127	96,885	253,404
Operating Income (Loss) ($)(1)	6,166	1,098	42,881	64,614	67,122	58,602	(53,180)	83,703
Operating Netback ($/boe)(1)	2.37	0.33	13.84	19.10	22.19	16.77	(14.80)	23.21
Capital expenditures ($)	5,811	76,246	69,796	42,664	33,717	52,964	65,399	74,509
Capital Expenditures Net of Capital-Carry ($)(1)	5,811	53,506	46,259	35,304	26,888	31,756	46,042	52,389
LIGHT OIL DIVISION								
Petroleum and natural gas production (boe/d)	9,466	8,242	8,642	10,023	10,210	11,712	12,609	10,135
Realized price ($/boe)	19.51	32.46	40.13	37.37	39.65	41.53	32.27	46.43
Petroleum and natural gas sales ($)(2)	16,806	24,347	31,904	34,462	36,836	43,778	37,434	43,294
Operating Income (Loss) ($)(1)	6,350	12,783	16,287	21,800	25,637	31,280	22,121	29,795
Operating Netback ($/boe)(1)	7.37	17.04	20.49	23.64	27.59	29.67	19.07	31.95
Capital expenditures ($)	1,089	58,527	46,473	21,501	11,858	29,855	39,569	60,739
Capital Expenditures Net of Capital-Carry ($)(1)	1,089	35,787	22,936	14,141	5,029	8,647	20,212	38,619
THERMAL OIL DIVISION								
Bitumen production (bbl/d)	17,601	28,315	27,761	25,234	23,748	27,494	25,375	30,477
Bitumen sales volumes (bbl/d)	19,045	29,095	25,049	26,744	23,028	27,100	26,462	29,074
Realized bitumen price ($/bbl)(1)	3.83	10.66	38.09	45.97	55.58	42.56	(11.74)	42.37
Blended bitumen sales ($)	39,231	114,153	156,197	181,876	187,695	182,349	59,451	210,110
Operating Income (Loss) ($)(1)	(24,619)	(33,111)	28,658	51,888	56,522	45,128	(84,544)	62,322
Operating Netback ($/bbl)(1)	(14.21)	(12.50)	12.44	21.09	26.97	18.50	(34.72)	23.30
Capital expenditures ($)	4,722	17,696	23,229	21,146	21,859	23,109	25,703	13,767
OPERATING RESULTS								
Cash flow from operating activities ($)	(31,186)	(3,021)	32,975	16,741	61,488	(18,572)	(2,253)	61,733
Adjusted Funds Flow ($)(1)	(16,214)	(27,883)	21,478	43,906	47,757	41,619	(75,296)	62,151
Net income (loss) ($)	(65,335)	(516,481)	(8,757)	(8,265)	57,091	206,796	(488,479)	31,419
Net income (loss) per share - basic ($)	(0.12)	(0.99)	(0.02)	(0.02)	0.11	0.40	(0.95)	0.06
BALANCE SHEET ITEMS								
Cash and cash equivalents ($)	167,442	199,517	254,389	255,433	292,851	272,240	73,898	128,340
Restricted cash ($)	152,125	110,634	110,609	110,629	111,092	106,385	111,056	114,216
Capital-carry receivable (discounted) ($)(3)	—	—	22,602	45,395	52,570	58,861	79,116	98,221
Total assets ($)	1,468,248	1,599,860	2,093,465	2,081,910	2,068,778	2,066,858	1,825,638	2,320,838
Long-term debt ($)(3)	594,488	617,123	559,687	569,750	560,538	570,411	581,140	546,505
Shareholders' equity ($)	640,515	705,055	1,220,062	1,227,214	1,232,912	1,172,954	965,949	1,452,946

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.
(2) Includes intercompany 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 six months ended June 30, 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, 2019 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. In the second quarter of 2020, economies have started to reopen leading to a partial recovery and stabilization 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 reductions in production levels;
- reduced capital program for 2020 which is not expected to impact production capability levels this year however further reductions to capital programs could have negative effects on future production levels;
- declines in commodity prices, revenue and cash flows leading to impairment charges (Note 7) 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 15 and 17).

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

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 and six months ended June 30, 2020 and 2019 to Adjusted Funds Flow:

	Three months ended June 30,		Six months ended June 30,	
($ Thousands)	**2020**	**2019**	**2020**	**2019**
Cash flow from operating activities	$ (31,186)	$ 61,488	$ (34,207)	$ 42,916
Restructuring expenses	5,703	—	5,703	—
Changes in non-cash working capital	9,148	(13,921)	(21,709)	43,479
Settlement of provisions	121	190	6,116	2,981
ADJUSTED FUNDS FLOW	$ (16,214)	$ 47,757	$ (44,097)	$ 89,376

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. 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 8 reconciles Light Oil Operating Income (Loss) to *Note 13 - Segmented Information* in the consolidated financial statements for the three and six months ended June 30, 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 blended bitumen sales and adjusting for the impacts of inventory write-downs (see table below). 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 12 reconciles Thermal Oil Operating Income (Loss) to *Note 13 - Segmented Information* in the consolidated financial statements for the three and six months ended June 30, 2020. The table below reconciles the Thermal Oil cost of diluent, operating expenses and transportation & marketing used to measure the Operating Income (Loss) to *Note 13 - Segmented Information* in the consolidated financial statements for the three months ended June 30, 2020. As no inventory adjustment was required for the six months ended June 30, 2020, no reconciliation was required between the Thermal Oil Operating Income (Loss) as disclosed in the MD&A and as reported in Note 13.

	Three months ended June 30, 2020		
($ Thousands, unless otherwise noted)	**Per MD&A**	**Inventory Write-down**	**Per Segment Note 13**
Blended bitumen sales	$ 39,231	$ —	$ 39,231
Cost of diluent	(32,598)	9,632	(22,966)
Total bitumen sales	6,633	9,632	16,265
Royalties	(166)	—	(166)
Operating expenses - non-energy	(9,268)	3,782	(5,486)
Operating expenses - energy	(8,238)	—	(8,238)
Transportation and marketing	(13,580)	2,050	(11,530)
Thermal Oil Operating Income (Loss)	$ (24,619)	$ 15,464	$ (9,155)

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 and adjusting for the impacts of inventory write-downs (see table below). 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 5 reconciles Consolidated Operating Income (Loss) to *Note 13 - Segmented Information* in the consolidated financial statements for the three and six months ended June 30, 2020. The table below reconciles the cost of diluent, operating expenses and transportation & marketing used to measure the Consolidated Operating Income (Loss) to the consolidated income statement for the three months ended June 30, 2020. As no inventory adjustment was required for the six months ended June 30, 2020, no reconciliation was required between the Consolidated Operating Income (Loss) as disclosed in the MD&A and as reported in Note 13.

	Three months ended June 30, 2020			
($ Thousands, unless otherwise noted)	**Per MD&A**	**Inventory Write-down**	**Eliminations**	**Per Income Statement**
Petroleum and natural gas sales	$ 56,037	$ —	$ (4,360)	$ 51,677
Royalties	(1,010)	—	—	(1,010)
Cost of diluent	(32,598)	9,632	4,360	(18,606)
Operating expenses	(22,978)	3,782	—	(19,196)
Transportation and marketing	(17,720)	2,050	—	(15,670)
	$ (18,269)	$ 15,464	$ —	$ (2,805)
Realized gain (loss) on commodity risk mgmt. contracts	24,435	—	—	24,435
Consolidated Operating Income (Loss)	$ 6,166	$ 15,464	$ —	$ 21,630

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

Comparative Figures

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

Internal Controls Update

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 second quarter of 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 bitumen, crude oil, natural gas and natural gas liquids reserves and resources;
- risks related to gathering and processing facilities and pipeline systems;
- reliance on third party infrastructure;
- 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 market prices for crude oil, natural gas, condensate and bitumen blend;
- 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 related to water disposal well at Leismer; expectation of results of CRA audits and reassessments; the Company's anticipated sources of funding for 2020 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, 2019 (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, including for petroleum, natural gas and blended bitumen; 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; 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; anticipated benefits of acquisitions and dispositions; ability to finance capital requirements; state of the capital markets; 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; aboriginal 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, 2019. There are numerous uncertainties inherent in estimating quantities of bitumen, crude oil, natural gas and natural gas liquids 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 6 of this MD&A include: 45 proved undeveloped or non-producing locations and 40 probable undeveloped locations for a total of 85 booked locations with the balance being unbooked locations. The 200 Montney drilling locations referenced on page 6 of this MD&A include: 77 proved undeveloped locations and 24 probable undeveloped locations for a total of 101 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, 2019 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, oil and natural gas 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, 2019, 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 and for the Dover West Sands asset area in the Development on Hold project maturity sub-class.

"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
LIBOR	London interbank offered rate
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
SAGD	steam assisted gravity drainage
US$	United States Dollars
WTI	West Texas Intermediate
WCS	Western Canadian Select