Management's Discussion and Analysis

Q3 2019

ATHABASCA OIL CORPORATION

This Management's Discussion and Analysis of the financial condition and results of operations ("MD&A") of Athabasca Oil Corporation ("Athabasca" or the "Company") is dated November 5, 2019 and should be read in conjunction with the audited consolidated financial statements of the Company for the years ended December 31, 2018 and 2017. 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 6, 2019 ("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 excellent 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

The Company's strategy is intended to ensure both its Light Oil and Thermal Oil businesses are financially robust and competitive, with exceptional future growth opportunities. The Company will continue its strategic emphasis on generating strong margins to maximize shareholder returns and generate free cash flow into the future.

HIGHLIGHTS FOR THE QUARTER AND NINE MONTHS ENDED SEPTEMBER 30, 2019

Corporate

- Third quarter production of 35,257 boe/d (87% liquids weighting).
- Adjusted Funds Flow(1) of $43.9 million in the third quarter and $133.3 million year to date.
- Consolidated Free Cash Flow(1) of $8.6 million in the third quarter and $39.3 million year to date.
- Year to date net income of $255.6 million.
- Strong balance sheet with total funding capacity of $382.3 million including $255.4 million of cash and cash equivalents, $80.6 million of available credit facilities and a $46.3 million (undiscounted) capital-carry balance.

Light Oil Division

- Third quarter production of 10,023 boe/d (55% liquids weighting).
- Strong third quarter and year to date Operating Netbacks(1) of $23.64/boe and $27.09/boe driven by high liquids weightings and low operating costs.
- Operating Income(1) of $21.8 million in the third quarter and $78.7 million year to date.
- Capital Expenditures Net of Capital-Carry(1) of $27.8 million year to date. Activity in Greater Kaybob included 9 (gross) wells drilled, 11 (gross) wells completed and 10 (gross) wells being placed on production. Drilling of a 4 (gross) well pad in Greater Placid was also commenced in the third quarter.

Thermal Oil Division

- Third quarter production of 25,234 bbl/d.
- Strong Operating Netbacks(1) of $21.09/bbl in the third quarter and $21.95/bbl year to date driven by strong realized bitumen pricing.
- Operating Income(1) of $51.9 million in the third quarter and $153.5 million year to date.
- Year to date capital expenditures of $66.1 million, including the drilling and completion of Pad 7 at Leismer which will support production into 2020. Production from Pad 7 will commence in the fourth quarter.
- Enhanced market access by securing capacity of approximately 7,200 bbl/d on the Keystone pipeline starting in 2020, providing the Company with access to Gulf Coast pricing.
- Secured 8,000 bbl/d of direct refinery sales in 2020 to mitigate apportionment risk on the Enbridge Mainline, and increased WCS hedging positions in 2020 to support cash flow.

(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 September 30, 2019	2018	Nine months ended September 30, 2019	2018
CONSOLIDATED				
Petroleum and natural gas production (boe/d)	35,257	40,612	36,126	39,614
Operating Income(1)(2)	$ 64,614	$ 83,703	$ 190,338	$ 147,298
Operating Netback(1)(2) ($/boe)	$ 19.10	$ 23.21	$ 19.24	$ 13.60
Capital expenditures	$ 42,664	$ 74,509	$ 129,345	$ 210,929
Capital Expenditures Net of Capital-Carry(1)	$ 35,304	$ 52,389	$ 93,948	$ 147,938
LIGHT OIL DIVISION				
Petroleum and natural gas production (boe/d)	10,023	10,135	10,642	10,832
Percentage liquids (%)	55%	51%	54%	50%
Operating Income(1)	$ 21,800	$ 29,795	$ 78,717	$ 85,023
Operating Netback(1) ($/boe)	$ 23.64	$ 31.95	$ 27.09	$ 28.76
Capital expenditures	$ 21,501	$ 60,739	$ 63,214	$ 152,926
Capital Expenditures Net of Capital-Carry(1)	$ 14,141	$ 38,619	$ 27,817	$ 89,935
THERMAL OIL DIVISION				
Bitumen production (bbl/d)	25,234	30,477	25,484	28,782
Operating Income(1)	$ 51,888	$ 62,322	$ 153,538	$ 95,213
Operating Netback(1) ($/bbl)	$ 21.09	$ 23.30	$ 21.95	$ 12.10
Capital expenditures	$ 21,146	$ 13,767	$ 66,114	$ 57,993
CASH FLOW AND FUNDS FLOW				
Cash flow from operating activities	$ 16,741	$ 61,733	$ 59,657	$ 86,097
per share - basic	$ 0.03	$ 0.12	$ 0.11	$ 0.17
Adjusted Funds Flow(1)	$ 43,906	$ 62,151	$ 133,282	$ 81,471
per share - basic	$ 0.08	$ 0.12	$ 0.26	$ 0.16
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)				
Net income (loss) and comprehensive income (loss)	$ (8,265)	$ 31,419	$ 255,622	$ (81,178)
per share - basic	$ (0.02)	$ 0.06	$ 0.49	$ (0.16)
per share - diluted	$ (0.02)	$ 0.06	$ 0.49	$ (0.16)
COMMON SHARES OUTSTANDING				
Weighted average shares outstanding - basic	523,263,183	515,792,185	520,604,599	513,575,091
Weighted average shares outstanding - diluted	523,263,183	527,414,170	525,461,794	513,575,091

As at ($ Thousands)	September 30, 2019	December 31, 2018
LIQUIDITY AND BALANCE SHEET		
Cash and cash equivalents	$ 255,433	$ 73,898
Available credit facilities(3)	$ 80,609	$ 126,491
Capital-carry receivable (current and long-term portion - undiscounted)	$ 46,278	$ 81,675
Face value of long-term debt(4)	$ 595,980	$ 614,070

(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 losses of $9.1 million and $41.9 million for the three and nine months ended September 30, 2019, respectively (September 30, 2018 - $8.4 million and $32.9 million).
(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 September 30, 2019 exchange rate of US$1.00 = C$1.3244.

BUSINESS ENVIRONMENT

Benchmark prices

(Average)	Three months ended September 30, 2019	2018	Change	Nine months ended September 30, 2019	2018	Change
Crude oil:						
West Texas Intermediate (WTI) (US$/bbl)[1]	$ 56.45	$ 69.50	(19)%	$ 57.06	$ 66.75	(15)%
West Texas Intermediate (WTI) (C$/bbl)[1]	$ 74.56	$ 90.84	(18)%	$ 75.87	$ 85.93	(12)%
Western Canadian Select (WCS) (C$/bbl)[2]	$ 58.36	$ 61.75	(5)%	$ 60.24	$ 57.76	4 %
Edmonton Par (C$/bbl)[3]	$ 68.21	$ 81.90	(17)%	$ 69.40	$ 78.23	(11)%
Edmonton Condensate (C5+) (C$/bbl)[4]	$ 68.03	$ 87.01	(22)%	$ 69.70	$ 84.69	(18)%
WCS Differential:						
to WTI (US$/bbl)	$ (12.24)	$ (22.25)	(45)%	$ (11.73)	$ (21.93)	(47)%
to WTI (C$/bbl)	$ (16.20)	$ (29.09)	(44)%	$ (15.63)	$ (28.17)	(45)%
Edmonton Par Differential:						
to WTI (US$/bbl)	$ (4.66)	$ (6.83)	(32)%	$ (4.71)	$ (6.06)	(22)%
to WTI (C$/bbl)	$ (6.35)	$ (8.94)	(29)%	$ (6.47)	$ (7.70)	(16)%
Natural gas:						
AECO (C$/GJ)[5][6]	$ 0.87	$ 1.13	(23)%	$ 1.44	$ 1.41	2 %
Chicago Citygate (US$/MMBtu)[6]	$ 2.08	$ 2.79	(25)%	$ 2.40	$ 2.80	(14)%
Foreign exchange:						
USD : CAD	1.32	1.31	1 %	1.33	1.29	3 %

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.

The Alberta Government announced mandatory industry production curtailments starting in January 2019 to alleviate the high differential situation. Following the curtailments, WCS heavy oil pricing and inventories have improved significantly. WCS prices have averaged $60.24/bbl year to date, an approximately 135% increase from $25.36/bbl in the fourth quarter of 2018. Recently the Alberta government announced a program to provide curtailment relief in an effort to stimulate additional egress through crude by rail. Athabasca is supportive of initiatives that increase egress capacity out of Western Canada but also views curtailments as a necessary tool for the government to have at its disposal to normalize pricing volatility if necessary until long term egress through pipelines is in place.

The global heavy oil market continues to be supported by structural supply declines in Venezuela and Mexico, OPEC cuts and growing petrochemical demand. These dynamics are supporting heavy oil pricing benchmarks with US refineries in PADD II and III requiring a heavier feedstock. The majority of North American liquids production growth is light or condensate spec and slated for export. Athabasca is well positioned for this changing dynamic with its Thermal Oil weighted production and long-life reserve base.

Athabasca's risk management program aims to protect a base level of capital activity while maintaining cash flow upside to the current pricing environment. For the fourth quarter of 2019, the Company has hedged 20,000 bbl/d with a WCS floor price of approximately C$53/bbl. For 2020, the Company has commenced its hedging program which currently includes 8,000 bbl/d of apportion protected WCS hedged at a differential of approximately US$19.50/bbl and 7,500 bbl/d of WTI hedged at a floor price of approximately US$55.75/bbl. The hedging program targets up to 50% of near term corporate production and Athabasca will layer on additional protection to support its 2020 capital plans.

Athabasca continues to pursue egress opportunities to enhance netbacks and diversify sales points for its production. The Company recently secured approximately 7,200 bbl/d of capacity on TC Energy's Keystone pipeline open season. The Capacity is expected to commence in 2020 and provides the Company direct exposure to the US Gulf Coast at pipeline economics. Athabasca also has 8,000 bbl/d of direct refinery sales in 2020 which mitigates potential apportionment risk. Long term, Athabasca has secured egress with 25,000 bbl/d of capacity on the TC Energy Keystone XL pipeline and 20,000 bbl/d of capacity on the Trans Mountain Expansion Project.

OUTLOOK

Athabasca continues to demonstrate its operational execution and fiscal prudence to protect its financial position during prolonged market headwinds and commodity price volatility. The Company has minimized its capital spend to ensure it is aligned with Adjusted Funds Flow, while preserving its strong liquidity. In 2019 the Company anticipates production of approximately 36,000 boe/d with Thermal Oil impacted by government curtailments, facility maintenance and the redistribution of steam across the field to support the startup of Leismer Pad L7. The 2019 capital program is $135 million with forecasted Adjusted Funds Flow of approximately $150 million (US$55 WTI & US$17.50 WCS differential for the balance of 2019).

The ramp up of new Pad L7 wells at Leismer and a winter program consisting of Placid and Duvernay well completions are expected to sustain production through 2020. Budget objectives for 2020 include activity focused on a minimal capital spend and alignment with Adjusted Funds Flow. Athabasca requires low sustaining capital to sustain its production base.

The Company remains focused on increasing Consolidated Free Cash Flow by improving break-evens and mitigating external risks. The Company has preserved long term optionality across a deep inventory of high-quality Thermal Oil projects and flexible Light Oil development opportunities. This diverse portfolio provides shareholders with significant exposure to liquids weighted production and long reserve life assets.

2019 Operational & Financial Guidance ($ millions, unless otherwise noted)	Full year
Corporate (net)	
Production (boe/d)	36,000
Capital Expenditures Net of Capital-Carry(1)(2)	$135
Adjusted Funds Flow(2)	$150
Commodity price assumptions	
WTI (US$/bbl)	$55.00
WCS differential (US$/bbl)	$17.50
AECO Gas (C$/Mcf)	$1.95
FX (US$/C$)	0.75

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

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 September 30,		Nine months ended September 30,	
	2019	2018	2019	2018
PRODUCTION				
Oil and condensate (bbl/d)	4,719	4,201	4,747	4,341
Natural gas (Mcf/d)	26,959	29,811	29,826	32,698
Natural gas liquids (bbl/d)	811	966	924	1,041
Bitumen (bbl/d)	25,234	30,477	25,484	28,782
Total (boe/d)	35,257	40,612	36,126	39,614

	Three months ended September 30,		Nine months ended September 30,	
($ Thousands, unless otherwise noted)	2019	2018	2019	2018
Petroleum and natural gas sales[1]	$ 216,338	$ 253,404	$ 666,996	$ 712,752
Royalties	(3,748)	(7,272)	(12,422)	(15,824)
Cost of diluent[1]	(68,772)	(96,779)	(218,529)	(325,504)
Operating expenses	(42,168)	(38,503)	(127,259)	(129,194)
Transportation and marketing	(27,962)	(18,733)	(76,531)	(61,994)
	$ 73,688	$ 92,117	$ 232,255	$ 180,236
Realized loss on commodity risk management contracts	(9,074)	(8,414)	(41,917)	(32,938)
Consolidated Operating Income[2]	$ 64,614	$ 83,703	$ 190,338	$ 147,298
REALIZED PRICES				
Oil and condensate ($/bbl)	$ 65.94	$ 81.81	$ 67.16	$ 78.21
Natural gas ($/Mcf)	1.69	2.57	2.47	2.69
Natural gas liquids ($/bbl)	22.15	52.22	31.29	52.48
Blended bitumen sales ($/bbl)	54.31	57.76	56.25	52.07
Realized price (net of cost of diluent) ($/boe)	43.63	43.42	45.30	35.76
Royalties ($/boe)	(1.11)	(2.02)	(1.25)	(1.46)
Operating expenses ($/boe)	(12.47)	(10.67)	(12.85)	(11.93)
Transportation and marketing ($/boe)	(8.27)	(5.19)	(7.73)	(5.73)
	$ 21.78	$ 25.54	$ 23.47	$ 16.64
Realized loss on commodity risk management contracts ($/boe)	(2.68)	(2.33)	(4.23)	(3.04)
CONSOLIDATED OPERATING NETBACK[2] ($/boe)	$ 19.10	$ 23.21	$ 19.24	$ 13.60

(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

	Three months ended September 30,		Nine months ended September 30,	
($ Thousands)	2019	2018	2019	2018
Consolidated Operating Income[1]	$ 64,614	$ 83,703	$ 190,338	$ 147,298
Unrealized gain (loss) on commodity risk management contracts	(8,452)	17,302	1,197	7,468
Depletion and depreciation	(31,988)	(41,981)	(97,971)	(120,929)
Gain on sale of assets	493	—	222,548	—
Exploration expenses	(1,149)	(331)	(1,946)	(792)
CONSOLIDATED SEGMENTS INCOME	$ 23,518	$ 58,693	$ 314,166	$ 33,045

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

Consolidated Capital Expenditures

($ Thousands)	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Light Oil Division	$ 21,501	$ 60,739	$ 63,214	$ 152,926
Thermal Oil Division	21,146	13,767	66,114	57,993
Corporate assets	17	3	17	10
TOTAL CAPITAL EXPENDITURES[1]	$ 42,664	$ 74,509	$ 129,345	$ 210,929
Less: Greater Kaybob capital-carry	(7,360)	(22,120)	(35,397)	(62,991)
TOTAL CAPITAL EXPENDITURES NET OF CAPITAL-CARRY[2]	$ 35,304	$ 52,389	$ 93,948	$ 147,938

(1) For the three and nine months ended September 30, 2019, capital expenditures include $2.1 million and $6.5 million of capitalized staff costs, respectively (September 30, 2018 - $2.8 million, $9.0 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

Overview

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, 2018, the Light Oil Division had approximately 74 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. Over the past two years, Athabasca has transitioned Greater Placid from early stage resource capture to efficient multi-well pad development. An inventory of over 200[1] high-graded gross drilling locations positions the Company for multi-year growth in this area.

In Greater Kaybob, Athabasca has a 30% non-operated interest in over 200,000 gross acres of commercially prospective Duvernay lands with exposure to both liquids-rich gas and volatile oil opportunities and an inventory of approximately 1,000[2] gross drilling locations. Seventy-five percent of Athabasca’s Greater Kaybob development capital is currently 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 capital-carry balance remaining at September 30, 2019 was $46.3 million (undiscounted).

(1) Based on the report of Athabasca's independent reserve evaluator effective December 31, 2018. Refer to the "Advisories and Other Guidance" section within this MD&A and the AIF for additional information about the Company's reserves and resources.
(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information regarding the Company's drilling locations.

Light Oil Operating Results

	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
PRODUCTION				
Oil and condensate (bbl/d)	4,719	4,201	4,747	4,341
Natural gas (Mcf/d)	26,959	29,811	29,826	32,698
Natural gas liquids (bbl/d)	811	966	924	1,041
Total (boe/d)	10,023	10,135	10,642	10,832
Consisting of:				
Greater Placid area (boe/d)	5,096	5,837	6,054	7,554
% liquids	43%	42%	45%	44%
Greater Kaybob area (boe/d)	4,927	4,298	4,588	3,278
% liquids	68%	63%	65%	63%

($ Thousands, unless otherwise noted)	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Petroleum and natural gas sales	$ 34,462	$ 43,294	$ 115,076	$ 131,583
Royalties	(867)	(1,771)	(3,365)	(4,729)
Operating expenses	(6,384)	(7,012)	(17,515)	(25,494)
Transportation and marketing	(5,411)	(4,716)	(15,479)	(16,337)
Light Oil Operating Income(1)	$ 21,800	$ 29,795	$ 78,717	$ 85,023
REALIZED PRICES				
Oil and condensate ($/bbl)	$ 65.94	$ 81.81	$ 67.16	$ 78.21
Natural gas ($/Mcf)	1.69	2.57	2.47	2.69
Natural gas liquids ($/bbl)	22.15	52.22	31.29	52.48
Realized price ($/boe)	37.37	46.43	39.61	44.50
Royalties ($/boe)	(0.94)	(1.90)	(1.16)	(1.60)
Operating expenses ($/boe)	(6.92)	(7.52)	(6.03)	(8.62)
Transportation and marketing ($/boe)	(5.87)	(5.06)	(5.33)	(5.52)
LIGHT OIL OPERATING NETBACK(1) ($/boe)	$ 23.64	$ 31.95	$ 27.09	$ 28.76

(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 10,023 boe/d and 10,642 boe/d during the three and nine months ended September 30, 2019, decreases of 1% and 2%, respectively, from the comparable 2018 periods. Production decreases were primarily the result of natural production decline in the Greater Placid area as Athabasca deferred winter activity late last year in response to the lower commodity price environment. In the Greater Kaybob area, 10 (gross) wells were brought on production in the first nine months of 2019, partially offsetting lower production in Greater Placid.

Athabasca’s Light Oil Operating Netback was $23.64/boe during the three months ended September 30, 2019, a decrease of 26% from the three months ended September 30, 2018. This decrease is primarily due to lower benchmark prices.

Athabasca’s Light Oil Operating Netback was $27.09/boe during the nine months ended September 30, 2019, a decrease of 6% from the comparable 2018 period. This decrease is primarily due to lower benchmark oil prices partially offset by a decrease in operating expenses as a result of lower water disposal and processing fees, as well as $3.6 million of prior period and equalization adjustments.

Athabasca generated Light Oil Operating Income of $21.8 million in the third quarter of 2019 and $78.7 million in the first nine months of 2019, decreases of 27% and 7% respectively from the comparable 2018 periods.

Light Oil Segment Income

($ Thousands)	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Light Oil Operating Income[1]	$ 21,800	$ 29,795	$ 78,717	$ 85,023
Depletion and depreciation	(17,452)	(16,613)	(55,044)	(52,413)
Loss on sale of assets	—	—	(1,205)	—
Exploration expenses	—	(35)	—	(40)
LIGHT OIL SEGMENT INCOME	$ 4,348	$ 13,147	$ 22,468	$ 32,570

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

Depletion and depreciation increased $0.8 million in the third quarter and $2.6 million in the first nine months of 2019 compared to the same periods in the prior year, primarily due to a higher depletion rate.

Light Oil Capital Expenditures

($ Thousands)	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Greater Placid	$ 11,189	$ 31,346	$ 15,261	$ 69,778
Greater Kaybob	10,312	29,393	47,953	83,148
TOTAL LIGHT OIL CAPITAL EXPENDITURES[1]	$ 21,501	$ 60,739	$ 63,214	$ 152,926
Less: Greater Kaybob capital-carry	(7,360)	(22,120)	(35,397)	(62,991)
TOTAL CAPITAL EXPENDITURES NET OF CAPITAL-CARRY[2]	$ 14,141	$ 38,619	$ 27,817	$ 89,935

(1) For the three and nine months ended September 30, 2019, capital expenditures include $0.9 million and $2.9 million of capitalized staff costs, respectively (September 30, 2018 - $1.2 million, $3.8 million).
(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 Greater Kaybob was $3.0 million and $12.6 million for the three and nine months ended September 30, 2019, respectively (September 30, 2018 - $7.3 million, $20.2 million).

During the nine months ended September 30, 2019, Light Oil capital expenditures of $63.2 million were primarily incurred at Greater Kaybob for drilling and completions, and to commence drilling of a four well pad at Greater Placid in the third quarter. The following table summarizes Athabasca's well activity for the three and nine months ended September 30, 2019 and 2018:

	Three months ended September 30,				Nine months ended September 30,			
	2019		2018		2019		2018	
Well activity[1]	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Greater Placid								
Wells drilled	—	—	2	1.4	—	—	8	5.6
Wells completed	—	—	6	4.2	—	—	11	7.7
Wells brought on production	—	—	—	—	—	—	5	3.5
Greater Kaybob								
Wells drilled	3	0.9	7	2.1	9	2.7	23	6.9
Wells completed	1	0.3	5	1.5	11	3.3	19	5.7
Wells brought on production	2	0.6	11	3.3	10	3.0	21	6.3

(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 two producing oil sands projects 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 over 40 years and a reserve life index of approximately 90 years (proved plus probable). The Leismer Project has Proved plus Probable Reserves of approximately 675 MMbbl(1) and 0.3 billion barrels (risked)(1) (0.3 billion barrels unrisked)(1) of Best Estimate Development Pending Contingent Resources. The Corner lease has Proved plus Probable Reserves of approximately 353 MMbbl(1) and 0.4 billion barrels (risked)(1) (0.5 billion barrels 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 producing Hangingstone Thermal Oil Project (the "Hangingstone Project"). The Hangingstone Project was commissioned in July 2015 and has proven reserves in place to support a flat production profile for over 40 years and a reserve life index of approximately 50 years (proved plus probable). Hangingstone has Proved plus Probable Reserves of approximately 177 MMbbl(1). Minimal development and maintenance capital will be required in the near-term to maintain Hangingstone production.

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. The Company recently secured approximately 7,200 bbl/d of blended bitumen capacity on the existing Keystone pipeline which is expected to start in 2020, diversifying its end market access to the US Gulf Coast. The Company has also 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 25,000 bbl/d of blended bitumen capacity on the Keystone XL pipeline which will further diversify the Company's access to multiple end markets.

Leismer Infrastructure Transaction

On December 10, 2018, Athabasca entered into an agreement with Enbridge Inc. ("Enbridge") for the sale of its Leismer pipelines and Cheecham storage terminal ("Leismer Infrastructure Transaction") for $265.0 million. The Leismer Infrastructure Transaction was completed on January 15, 2019 and provides Athabasca with priority service on the pipelines and access to the dilbit/diluent tanks at Cheecham for an annual toll of approximately $26.0 million, with a discounted toll for any excess volumes.

During the first quarter of 2019, Athabasca received $265.0 million of cash consideration from Enbridge and incurred $2.8 million of transaction costs, resulting in net proceeds of $262.2 million. Athabasca de-recognized $39.9 million of PP&E and $0.4 million in decommissioning obligations resulting in a gain of $222.8 million on the Leismer Infrastructure Transaction.

(1) Based on the report of Athabasca's independent reserve evaluator effective December 31, 2018. Refer to the "Advisories and Other Guidance" section within this MD&A and the AIF for additional information about the Company's reserves and resources.

Leismer Operating Results

	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
VOLUMES				
Bitumen production (bbl/d)	16,557	20,975	16,981	19,469
Bitumen sales (bbl/d)	17,144	21,026	17,044	19,652
Blended bitumen sales (bbl/d)	22,875	28,199	23,500	27,521

($ Thousands, unless otherwise noted)	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Blended bitumen sales	$ 115,260	$ 147,976	$ 361,520	$ 383,984
Cost of diluent	(40,620)	(66,852)	(136,038)	(215,716)
Total bitumen sales	74,640	81,124	225,482	168,268
Royalties	(2,028)	(4,040)	(6,443)	(7,979)
Operating expenses - non-energy	(16,294)	(12,937)	(47,467)	(40,103)
Operating expenses - energy	(4,940)	(5,246)	(19,522)	(16,277)
Transportation and marketing	(11,526)	(5,604)	(31,549)	(16,203)
Leismer Operating Income(1)	$ 39,852	$ 53,297	$ 120,501	$ 87,706
REALIZED PRICE				
Blended bitumen sales ($/bbl)	$ 54.77	$ 57.04	$ 56.35	$ 51.11
Bitumen sales ($/bbl)	$ 47.32	$ 41.94	$ 48.46	$ 31.36
Royalties ($/bbl)	(1.29)	(2.09)	(1.38)	(1.49)
Operating expenses - non-energy ($/bbl)	(10.33)	(6.69)	(10.20)	(7.47)
Operating expenses - energy ($/bbl)	(3.13)	(2.71)	(4.20)	(3.03)
Transportation and marketing ($/bbl)	(7.31)	(2.90)	(6.78)	(3.02)
LEISMER OPERATING NETBACK(1) ($/bbl)	$ 25.26	$ 27.55	$ 25.90	$ 16.35

(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 third quarter and first nine months of 2019 was 21% and 13% lower, respectively, relative to the comparable periods in 2018. Production in 2019 was impacted by mandated government curtailments early in the year, facility maintenance during the second quarter, and the redistribution of steam across the field to support the startup of Leismer's Pad 7. Pad 7 is composed of five well pairs, each with approximately 1,250 meter laterals (50% longer than prior wells). Steaming commenced in June and all five well pairs are expected to support production during the fourth quarter. New well pairs are expected to ramp-up in the first half of 2020.

The Leismer Operating Netback was $25.26/bbl during the third quarter of 2019, a decrease of 8% compared to the comparable 2018 period primarily due to lower WCS benchmark oil prices, higher operating and transportation expenses, partially offset by lower diluent costs. During the first nine months of 2019, the Leismer Operating Netback was $25.90/bbl, an increase of 58% compared to the comparable 2018 period primarily a result of higher WCS benchmark oil prices and lower diluent costs, partially offset by higher operating and transportation expenses.

Total operating expenses were $13.46/bbl in the third quarter of 2019 and $14.40/bbl in the first nine months of 2019, compared to $9.40/bbl and $10.50/bbl in the comparable periods of 2018. Non-energy costs per bbl in 2019 have increased relative to the prior year primarily due to lower production volumes, higher short-term water disposal costs and higher maintenance costs. In the first nine months of 2019, energy operating costs per barrel were higher relative to the prior year primarily due to higher power prices and the redistribution of steam during circulation of the Pad L7 well pairs.

Transportation and marketing expenses have increased in 2019 relative to 2018 due to lower production volumes and the new pipeline and storage tolls incurred by Athabasca following the Leismer Infrastructure Transaction.

Leismer Operating Income was $39.9 million in the third quarter of 2019 compared to $53.3 million in the third quarter of 2018. Year to date Operating Income was $120.5 million, representing a 37% increase year-over-year.

Seasonality can have an impact on Operating Income generated by the Thermal Oil business. In the second and third quarters of a given year, dilution costs will generally decrease as less diluent is required to meet pipeline specifications.

Hangingstone Operating Results

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	2019	2018
VOLUMES				
Bitumen production (bbl/d)	8,677	9,502	8,503	9,313
Bitumen sales (bbl/d)	9,600	8,048	8,578	9,181
Blended bitumen sales (bbl/d)	13,525	11,342	12,441	13,365

	Three months ended September 30,		Nine months ended September 30,	
($ Thousands, unless otherwise noted)	2019	2018	2019	2018
Blended bitumen sales	$ 66,616	$ 62,134	$ 190,400	$ 197,185
Cost of diluent	(28,152)	(29,927)	(82,491)	(109,788)
Total bitumen sales	38,464	32,207	107,909	87,397
Royalties	(853)	(1,461)	(2,614)	(3,116)
Operating expenses - non-energy	(10,310)	(9,035)	(28,105)	(33,733)
Operating expenses - energy	(4,240)	(4,273)	(14,650)	(13,587)
Transportation and marketing	(11,025)	(8,413)	(29,503)	(29,454)
Hangingstone Operating Income[(1)]	$ 12,036	$ 9,025	$ 33,037	$ 7,507
REALIZED PRICE				
Blended bitumen sales ($/bbl)	$ 53.54	$ 59.55	$ 56.06	$ 54.04
Bitumen sales ($/bbl)	$ 43.55	$ 43.50	$ 46.08	$ 34.87
Royalties ($/bbl)	(0.97)	(1.97)	(1.12)	(1.24)
Operating expenses - non-energy ($/bbl)	(11.67)	(12.20)	(12.00)	(13.46)
Operating expenses - energy ($/bbl)	(4.80)	(5.77)	(6.26)	(5.42)
Transportation and marketing ($/bbl)	(12.48)	(11.36)	(12.60)	(11.75)
HANGINGSTONE OPERATING NETBACK[(1)] ($/bbl)	$ 13.63	$ 12.20	$ 14.10	$ 3.00

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

Hangingstone production in the third quarter and first nine months of 2019 was 9% lower than the comparable periods of 2018. Production in 2019 was impacted by facility downtime in the second quarter and the subsequent recovery from maintenance activities.

Hangingstone realized an Operating Netback of $13.63/bbl in the third quarter of 2019, an increase of 12% compared to the same period in 2018, primarily due to lower operating expenses and diluent costs partially offset by lower WCS benchmark oil prices. The Hangingstone Operating Netback was $14.10/bbl in the first nine months of 2019, an increase of $11.10/bbl as compared to the same period in 2018, primarily due to higher WCS benchmark oil prices and lower diluent costs per barrel.

Total operating expenses were $16.47/bbl in the third quarter of 2019 compared to $17.97/bbl during the same period in 2018, and $18.26/bbl in the first nine months of 2019 compared to $18.88/bbl during the same period in 2018. Non-energy costs per bbl have decreased in 2019 primarily due to the successful optimization of field operations over the past year, partially offset by lower production volumes. In the third quarter of 2019, energy operating costs per bbl were lower than the prior year primarily due to lower gas and power prices. In the first nine months of 2019, energy operating costs per bbl were higher than the prior year primarily due to higher power prices.

Hangingstone Operating Income was $12.0 million in the third quarter of 2019 compared to $9.0 million in the third quarter of 2018, and $33.0 million in the first nine months of 2019 compared to $7.5 million in the first nine months of 2018.

Seasonality can have an impact on Operating Income generated by the Thermal Oil business. In the second and third quarters of a given year, dilution costs will generally decrease as less diluent is required to meet pipeline specifications.

Consolidated Thermal Oil Operating Results

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	2019	2018
VOLUMES				
Bitumen production (bbl/d)	25,234	30,477	25,484	28,782
Bitumen sales (bbl/d)	26,744	29,074	25,622	28,833
Blended bitumen sales (bbl/d)	36,400	39,541	35,941	40,886

($ Thousands, unless otherwise noted)	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Blended bitumen sales	$ 181,876	$ 210,110	$ 551,920	$ 581,169
Cost of diluent	(68,772)	(96,779)	(218,529)	(325,504)
Total bitumen sales	113,104	113,331	333,391	255,665
Royalties	(2,881)	(5,501)	(9,057)	(11,095)
Operating expenses - non-energy	(26,604)	(21,972)	(75,572)	(73,836)
Operating expenses - energy	(9,180)	(9,519)	(34,172)	(29,864)
Transportation and marketing	(22,551)	(14,017)	(61,052)	(45,657)
Thermal Oil Operating Income[(1)]	$ 51,888	$ 62,322	$ 153,538	$ 95,213
REALIZED PRICE				
Blended bitumen sales ($/bbl)	$ 54.31	$ 57.76	$ 56.25	$ 52.07
Bitumen sales ($/bbl)	$ 45.97	$ 42.37	$ 47.66	$ 32.48
Royalties ($/bbl)	(1.17)	(2.06)	(1.29)	(1.41)
Operating expenses - non-energy ($/bbl)	(10.81)	(8.21)	(10.80)	(9.38)
Operating expenses - energy ($/bbl)	(3.73)	(3.56)	(4.89)	(3.79)
Transportation and marketing ($/bbl)	(9.17)	(5.24)	(8.73)	(5.80)
THERMAL OIL OPERATING NETBACK[(1)] ($/bbl)	$ 21.09	$ 23.30	$ 21.95	$ 12.10

(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

($ Thousands)	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Thermal Oil Operating Income[(1)]	$ 51,888	$ 62,322	$ 153,538	$ 95,213
Depletion and depreciation	(14,536)	(25,368)	(42,927)	(68,516)
Gain on sale of assets	493	—	223,753	—
Exploration expenses	(1,149)	(296)	(1,946)	(752)
THERMAL OIL SEGMENT INCOME	$ 36,696	$ 36,658	$ 332,418	$ 25,945

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

Depletion and depreciation expense decreased $10.8 million in the third quarter of 2019 and $25.6 million in the first nine months of 2019 compared to the same periods in the prior year primarily due to lower production volumes and a decrease in the Hangingstone depletion rate.

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 September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Leismer Project	$ 18,374	$ 10,134	$ 60,048	$ 48,223
Hangingstone Project	2,631	2,080	5,818	7,251
Other Thermal Oil exploration	141	1,553	248	2,519
TOTAL THERMAL OIL CAPITAL EXPENDITURES(1)	$ 21,146	$ 13,767	$ 66,114	$ 57,993

(1) For the three and nine months ended September 30, 2019, capital expenditures include $1.2 million and $3.6 million of capitalized staff costs, respectively (September 30, 2018 - $1.6 million, $5.2 million).

Thermal Oil capital expenditures of $66.1 million for the first nine months of 2019 were primarily associated with the drilling and completions of five well pairs and four observation wells on Pad 7 and a steam debottleneck project at Leismer which will provide future operational flexibility. Capital expenditures also included downhole pump replacements at both Leismer and Hangingstone.

In 2019, Athabasca received two government grants to support funding of certain capital projects designed to reduce the emissions intensity of Athabasca's assets. In 2019, Athabasca has recognized $4.1 million related to these grants.

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 funds for anticipated short-term spending and to manage periods of volatility within its cash, cash equivalent and short-term investment accounts as well as through available credit facilities.

As at September 30, 2019, Athabasca had liquidity of $336.0 million, including $255.4 million of unrestricted cash and cash equivalents, $80.4 million of available credit under its Credit Facility (defined below), and $0.2 million of available credit under its Unsecured Letter of Credit Facility (defined below). In addition, the Company had $46.3 million (undiscounted) of funding available through the capital-carry receivable.

In 2019 and 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, the capital-carry receivable, existing cash and cash equivalents and available credit facilities. In the future, 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 the current availability of the equity and debt capital markets.

Indebtedness

As at ($ Thousands)	September 30, 2019	December 31, 2018
2022 Notes(1)	$ 595,980	$ 614,070
Debt issuance costs	(47,081)	(47,081)
Amortization of debt issuance costs	20,851	14,151
TOTAL LONG-TERM DEBT	$ 569,750	$ 581,140

(1) As at September 30, 2019, the US dollar denominated 2022 Notes were translated into Canadian dollars at the period end exchange rate of US$1.00 = C$1.3244.

Athabasca had the following debt instruments and credit facilities in place as at September 30, 2019:

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, 2019 to February 23, 2020 - 104.9% of principal
- 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 2019, Athabasca renewed its $120.0 million reserve-based credit facility (the "Credit Facility"). The Credit Facility is a 364 day committed facility available on a revolving basis until May 31, 2020, at which time it may be extended at the lenders' option. If the revolving period is not extended, the undrawn portion of the facility will be cancelled and any amounts outstanding would be repayable at the end of the non-revolving term, being May 31, 2021. The Credit Facility is subject to a semi-annual borrowing base review, occurring approximately in May and November of each year. The borrowing base is determined based on the lender's evaluation of the Company's petroleum and natural gas reserves and their commodity price outlook at the time of each renewal, which could result in an increase or a reduction to the Credit Facility.

As at September 30, 2019, amounts borrowed under the Credit Facility bear interest at a floating rate based on the applicable Canadian prime rate, US base rate, LIBOR or bankers' acceptance rate, plus a margin of 2.5% to 3.5%. The Company incurs an issuance fee for letters of credit of 3.5% and a standby fee on the undrawn portion of the Credit Facility of 0.8%. As at September 30, 2019, the Company had no amounts drawn and had $39.6 million of letters of credit issued and outstanding under the Credit Facility. As at December 31, 2018, the Company had no amounts drawn or letters of credit issued and outstanding under the Credit Facility.

Cash-Collateralized Letter of Credit Facility

Athabasca maintains a $110.0 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%. 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 September 30, 2019, Athabasca had $109.5 million (December 31, 2018 - $110.0 million) in letters of credit issued and outstanding under the Letter of Credit Facility.

Unsecured Letter of Credit Facility

In the fourth quarter of 2018, Athabasca entered into a $25.0 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 2.2%. As at September 30, 2019, the Company had $24.8 million of letters of credit issued and outstanding under the Unsecured Letter of Credit Facility (December 31, 2018 - $18.5 million).

Financing and Interest

	Three months ended September 30,		Nine months ended September 30,	
($ Thousands)	**2019**	**2018**	**2019**	**2018**
Financing and interest expense on indebtedness	$ 15,275	$ 15,328	$ 45,722	$ 45,113
Amortization of debt issuance costs	2,367	2,210	6,860	6,349
Accretion of provisions	2,918	2,903	8,617	8,609
Interest expense on lease liability	425	—	1,317	—
TOTAL FINANCING AND INTEREST	$ 20,985	$ 20,441	$ 62,516	$ 60,071

During the three and nine months ended September 30, 2019 and 2018, financing and interest expenses were primarily attributable to the Company's 2022 Notes. The interest expense on the lease liability relates to the adoption of IFRS 16 *Leases* on January 1, 2019 which resulted in a new implied interest expense of $0.4 million and $1.3 million during the three and nine months ended September 30, 2019, respectively.

Foreign Exchange Gain (Loss), Net

($ Thousands)	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Unrealized foreign exchange gain (loss)	$ (6,885)	$ 9,834	$ 18,090	$ (16,206)
Realized foreign exchange gain (loss)	(5)	(164)	708	(381)
FOREIGN EXCHANGE GAIN (LOSS), NET	$ (6,890)	$ 9,670	$ 18,798	$ (16,587)

Athabasca is exposed to foreign currency risk 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 (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.

Financial commodity risk management contracts

As at September 30, 2019, the following financial commodity risk management contracts were in place:

Instrument	Period	Volume	C$ Average Price/bbl[1]	US$ Average Price/bbl[1]
WTI fixed price swaps	October - December 2019	18,000 bbl/d	$ 80.23	$ 60.58
WTI/WCS differential swaps	October - December 2019	21,000 bbl/d	$ (26.69)	$ (20.16)
WTI costless collar	October - December 2019	2,000 bbl/d	$ 80.00 - 86.10	$ 60.40 - 65.01
WTI/WCS differential swaps	January - March 2020	9,000 bbl/d	$ (26.53)	$ (20.03)
WTI/WCS differential swaps	April - June 2020	9,000 bbl/d	$ (25.08)	$ (18.93)
WTI/WCS differential swaps	July - September 2020	7,000 bbl/d	$ (26.17)	$ (19.76)
WTI/WCS differential swaps	October - December 2020	7,000 bbl/d	$ (26.17)	$ (19.76)
WTI three way collar	January - December 2020	1,000 bbl/d	$ 65.56 | 79.46 | 86.09	$ 49.50 | 60.00 | 65.00

(1) The implied C$ or US$ Average Price/bbl, as applicable, was calculated using the September 30, 2019 exchange rate of US$1.00 = C$1.3244.

The following table summarizes the Company's net gain (loss) on commodity risk management contracts for the three and nine months ended September 30, 2019 and 2018:

($ Thousands)	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Unrealized gain (loss) on commodity risk management contracts	$ (8,452)	$ 17,302	$ 1,197	$ 7,468
Realized loss on commodity risk management contracts	(9,074)	(8,414)	(41,917)	(32,938)
GAIN (LOSS) ON COMMODITY RISK MANAGEMENT CONTRACTS, NET	$ (17,526)	$ 8,888	$ (40,720)	$ (25,470)

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

As at September 30, 2019	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	$ (14,521)	$ 13,038	$ 6,203	$ (6,214)

Additional financial commodity risk management activity related to 2020 has taken place subsequent to September 30, 2019, as noted in the table below:

Instrument	Period	Volume	C$ Average Price/bbl(1)	US$ Average Price/bbl(1)
WTI fixed price swaps	January - March 2020	3,000 bbl/d	$ 73.19	$ 55.26
WTI fixed price swaps	April - June 2020	3,000 bbl/d	$ 72.93	$ 55.07
WTI three way collar	January - December 2020	5,000 bbl/d	$ 65.69|72.84|79.46	$ 49.60|55.00|60.00

(1) The implied C$ or US$ Average Price/bbl, as applicable, was calculated using the September 30, 2019 exchange rate of US$1.00 = C$1.3244.

Foreign exchange contracts

As at September 30, 2019, Athabasca had no foreign exchange risk management contracts in place. As at December 31, 2018, Athabasca had a foreign exchange risk management asset of $2.5 million in respect of a foreign exchange risk management contract associated with the February 2019 interest payment on the Company's 2022 Notes.

The following table summarizes the net gain (loss) on foreign exchange risk management contracts for the three and nine months ended September 30, 2019 and 2018:

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	2019	2018
Unrealized gain (loss) on foreign exchange risk management contracts	$ 372	$ (1,763)	$ (2,495)	$ 826
Realized gain on foreign exchange risk management contracts	118	1,071	1,733	1,071
GAIN (LOSS) ON FOREIGN EXCHANGE RISK MANAGEMENT CONTRACTS, NET	$ 490	$ (692)	$ (762)	$ 1,897

The net gain (loss) on foreign exchange risk management contracts is due to fluctuations in the USD/CAD forward exchange rates and the settlement of the contracts.

Commitments and Contingencies

The following table summarizes Athabasca’s estimated future minimum commitments as at September 30, 2019 for the following five years and thereafter:

($ Thousands)	Remaining 2019	2020	2021	2022	2023	Thereafter	Total
Transportation and processing(1)	$ 31,271	$ 130,307	$ 128,908	$ 155,439	$ 238,322	$ 4,120,765	$ 4,805,012
Repayment of long-term debt(1)	—	—	—	595,980	—	—	595,980
Interest expense on long-term debt(1)	—	58,853	58,853	29,427	—	—	147,133
Purchase commitments and drilling rigs	6,133	610	—	—	—	—	6,743
TOTAL COMMITMENTS	$ 37,404	$ 189,770	$ 187,761	$ 780,846	$ 238,322	$ 4,120,765	$ 5,554,868

(1) Commitments which are denominated in US dollars were translated into Canadian dollars at the September 30, 2019 exchange rate of US$1.00 = C$1.3244.

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, expected to start in 2020, as part of TC Energy's recently completed open season for incremental capacity on the existing Keystone pipeline. As part of the commitment, Athabasca also entered into a development cost agreement which could require a conditional payment of US$48 million ($64.1 million), which is only payable, if shipper agreements on the Keystone XL pipeline are terminated on or before January 31, 2020. Athabasca has provided financial assurances in the amount of $83.3 million, consisting of $33.1 million (US$25 million) of cash and $50.2 million of letters of credit, in connection with these new agreements. In the event the conditional payment is not required, $64.1 million of the financial assurances will be returned to the Company in early 2020.

In conjunction with the Leismer Infrastructure Transaction, Athabasca entered into a new commitment on January 15, 2019 for priority service on the pipelines and access to the dilbit/diluent tanks with an annual toll of approximately $26 million.

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 believes that it has appropriately assessed any impact to the consolidated financial statements.

Other Corporate Items

General and Administrative ("G&A")

	Three months ended September 30,		Nine months ended September 30,	
($ Thousands, unless otherwise noted)	2019	2018	2019	2018
TOTAL GENERAL AND ADMINISTRATIVE	$ 5,965	$ 7,550	$ 16,443	$ 22,987
G&A per boe	$ 1.84	$ 2.02	$ 1.67	$ 2.13

During the three and nine months ended September 30, 2019, Athabasca's G&A expenses decreased compared to the same periods in the prior year, primarily due to lower employee costs resulting from staff reductions in 2018. G&A in 2019 was also impacted by the adoption of IFRS 16 *Leases* which resulted in decreases to G&A of $0.7 million and $2.1 million, respectively.

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

	Three months ended September 30,		Nine months ended September 30,	
($ Thousands)	2019	2018	2019	2018
Contingent payment obligation gain (loss)	$ 1,680	$ (8,424)	$ 3,103	$ (16,236)
Capital-carry receivable gain	185	1,323	1,676	5,176
Other	—	13	(9)	1,763
GAIN (LOSS) ON REVALUATION OF PROVISIONS AND OTHER, NET	$ 1,865	$ (7,088)	$ 4,770	$ (9,297)

The gains or losses on revaluation of the contingent payment obligation are primarily due to fluctuations in forecasted prices for WTI. In early 2017, as part of the acquisition of the Leismer / Corner Thermal Oil assets, Athabasca agreed to a contingent payment obligation for a four-year term ending in 2020 which is triggered at oil prices above US$65/bbl WTI. The payments are determined annually and calculated on one-third of annual Leismer bitumen production multiplied by an oil price factor (yearly average US$WTI/bbl less US $65/bbl, adjusted for inflation since 2017). The payments are capped at $75.0 million annually. The contingent payment obligation is remeasured at each reporting period using an option pricing model with any gains or losses recognized in net income (loss). The option pricing model includes estimates regarding future WTI prices, foreign exchange rates, inflation rates and Leismer production volumes and is therefore subject to significant measurement uncertainty. The difference in the actual cash outflows associated with the obligation could be material.

Income Taxes

From time to time, Athabasca undergoes income tax audits in the normal course of business. In May 2018, the Company received a notice of reassessment from the Canada Revenue Agency ("CRA") with regards to its 2012 taxation year. While the final outcome of such reassessment cannot be predicted with certainty, Athabasca has received legal advice that confirms its position as filed and believes it is likely to be successful in appealing the reassessment. As such, the Company has not recognized any provision in its consolidated financial statements with respect to the reassessment and has posted a deposit with the CRA in order to file an objection against the reassessment.

The Company has approximately $3.1 billion in tax pools, including approximately $2.0 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 and legislative delays is a significant risk to Athabasca and could have a material impact on future financial results. Additional information is available in Athabasca's AIF that is filed on the Company's SEDAR profile at www.sedar.com.

Off Balance Sheet Arrangements

The Company does not have any off-balance sheet arrangements that have or are reasonably likely to have a material current or future effect on the Company's consolidated financial statements.

Outstanding Share Data

As at September 30, 2019, there were 523.4 million common shares outstanding, an aggregate of 25.5 million restricted share units, performance share units and deferred shares units outstanding, and 9.0 million stock options outstanding. There were no material changes in these balances between September 30, 2019 and November 5, 2019.

During the three and nine months ended September 30, 2019, Athabasca issued 0.2 million and 7.5 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:

	2019			2018				2017
($ Thousands, unless otherwise noted)	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	56.45	59.82	54.90	58.81	69.50	67.90	62.87	55.40
WTI (C$/bbl)	74.56	80.11	72.97	77.70	90.84	87.67	79.53	70.47
Western Canadian Select (C$/bbl)	58.36	65.73	56.62	25.36	61.75	62.89	48.77	54.87
Edmonton Par (C$/bbl)	68.21	73.60	66.41	42.75	81.90	80.60	72.06	69.02
Edmonton Condensate (C5+) (C$/bbl)	68.03	74.46	66.60	59.73	87.01	88.87	79.74	73.74
AECO (C$/GJ)	0.87	0.98	2.49	1.48	1.13	1.12	1.97	1.60
Chicago Citygate (US$/MMBtu)	2.08	2.31	2.82	3.67	2.79	2.67	2.95	2.86
Foreign exchange (USD : CAD)	1.32	1.34	1.33	1.32	1.31	1.29	1.27	1.27
CONSOLIDATED								
Petroleum and natural gas production (boe/d)	35,257	33,958	39,206	37,984	40,612	37,658	40,572	42,064
Realized price (net of cost of diluent) ($/boe)	43.63	50.69	42.25	2.47	43.42	39.73	24.23	36.95
Petroleum and natural gas sales ($)(1)	216,338	224,531	226,127	96,885	253,404	251,369	207,979	238,835
Operating Income (Loss) ($)(2)	64,614	67,122	58,602	(53,180)	83,703	46,719	16,876	65,002
Operating Netback ($/boe)(2)	19.10	22.19	16.77	(14.80)	23.21	13.01	4.65	17.25
Capital expenditures ($)	42,664	33,717	52,964	65,399	74,509	54,159	82,261	52,418
Capital Expenditures Net of Capital-Carry ($)(2)	35,304	26,888	31,756	46,042	52,389	38,888	56,661	33,236
LIGHT OIL DIVISION								
Petroleum and natural gas production (boe/d)	10,023	10,210	11,712	12,609	10,135	11,872	10,495	11,507
Realized price ($/boe)	37.37	39.65	41.53	32.27	46.43	42.68	44.65	40.10
Petroleum and natural gas sales ($)	34,462	36,836	43,778	37,434	43,294	46,107	42,182	42,456
Operating Income ($)(2)	21,800	25,637	31,280	22,121	29,795	30,936	24,292	26,696
Operating Netback ($/boe)(2)	23.64	27.59	29.67	19.07	31.95	28.64	25.72	25.22
Capital expenditures ($)	21,501	11,858	29,855	39,569	60,739	25,557	66,630	40,988
Capital Expenditures Net of Capital-Carry ($)(2)	14,141	5,029	8,647	20,212	38,619	10,286	41,030	21,806
THERMAL OIL DIVISION								
Bitumen production (bbl/d)	25,234	23,748	27,494	25,375	30,477	25,786	30,077	30,557
Bitumen sales volumes (bbl/d)	26,744	23,028	27,100	26,462	29,074	27,578	29,857	29,447
Realized bitumen price ($/bbl)	45.97	55.58	42.56	(11.74)	42.37	38.46	17.05	35.72
Blended bitumen sales ($)	181,876	187,695	182,349	59,451	210,110	205,262	165,797	196,379
Operating Income (Loss) ($)(2)	51,888	56,522	45,128	(84,544)	62,322	39,635	(6,744)	45,385
Operating Netback ($/bbl)(2)	21.09	26.97	18.50	(34.72)	23.30	15.79	(2.51)	16.75
Capital expenditures ($)	21,146	21,859	23,109	25,703	13,767	28,595	15,631	11,368
OPERATING RESULTS								
Cash flow from operating activities ($)	16,741	61,488	(18,572)	(2,253)	61,733	27,605	(3,241)	37,060
Adjusted Funds Flow ($)(2)	43,906	47,757	41,619	(75,296)	62,151	25,680	(6,360)	41,808
Net income (loss) ($)	(8,265)	57,091	206,796	(488,479)	31,419	(19,267)	(93,330)	(209,588)
Net income (loss) per share - basic ($)	(0.02)	0.11	0.40	(0.95)	0.06	(0.04)	(0.18)	(0.41)
BALANCE SHEET ITEMS								
Cash and cash equivalents ($)	255,433	292,851	272,240	73,898	128,340	93,293	128,915	163,321
Restricted cash ($)	110,629	111,092	106,385	111,056	114,216	114,212	111,778	113,406
Capital-carry receivable (discounted) ($)(3)	45,395	52,570	58,861	79,116	98,221	119,018	132,745	156,036
Total assets ($)	2,081,910	2,068,778	2,066,858	1,825,638	2,320,838	2,297,112	2,318,471	2,323,572
Long-term debt ($)(3)	569,750	560,538	570,411	581,140	546,505	554,279	541,460	526,206
Shareholders' equity ($)	1,227,214	1,232,912	1,172,954	965,949	1,452,946	1,418,587	1,434,345	1,524,610

(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.
(3) Balances include the current and long-term portions as reported in the consolidated balance sheets.

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

ACCOUNTING POLICIES AND ESTIMATES

During the three and nine months ended September 30, 2019, 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, except as noted below. Refer to the December 31, 2018 audited consolidated financial statements for the Company for further guidance regarding Athabasca's accounting policies and use of estimates.

Changes in accounting policies

IFRS 16 *Leases*

On January 1, 2019, Athabasca adopted the new IASB Lease Standard IFRS 16. IFRS 16 requires that former operating leases be capitalized and recognized on the consolidated balance sheet by the lessee. Lease assets and liabilities are initially measured at the present value of the unavoidable lease payments and amortized over the lease term. Lessor accounting remains consistent with current IFRS standards. Athabasca adopted IFRS 16 using a modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information and recognizes the cumulative effect of IFRS 16 prior to January 1, 2019 as an adjustment to the opening retained deficit and applies the standard prospectively. On adoption, Athabasca also elected to apply the following expedients as permitted under the standard:

- Leases with terms ending within 12 months are recognized as short-term leases.
- Short-term leases and leases of low value assets that have been identified are not recognized on the consolidated balance sheet. Expenses for these leases are recognized as incurred with the amounts disclosed in the notes to the consolidated financial statements.
- The provision for onerous leases previously recognized was applied to the value of the associated right-of-use asset ("Leased asset"). In this case, no impairment assessment was performed under IAS 36 *Impairment.*

Upon adoption, Athabasca recognized a Leased asset of $12.6 million within PP&E and a lease liability of $18.7 million within provisions and other liabilities relating to its head office lease. The liability was measured at the present value of the remaining lease payments using an incremental borrowing rate of 10.0%. Athabasca netted the previously recognized onerous office lease provision of $3.1 million against the associated Leased asset on January 1, 2019. An adjustment to the opening retained deficit of $3.0 million was recognized as a result of using the modified retrospective approach.

During the three and nine months ended September 30, 2019, interest expense increased by $0.4 million and $1.3 million, depreciation increased by $0.5 million and $1.5 million and general and administrative expense decreased by $0.7 million and $2.1 million as a result of the adoption of IFRS 16, respectively. For the three and nine months ended September 30, 2019, cash flows associated with the lease repayments of $1.0 million and $3.0 million were allocated between operating and financing activities based on their interest and principal repayment components, respectively. For the three and nine months ended September 30, 2019, cash flows associated with the lease repayments of $0.4 million and $1.3 million were allocated to operating activities and $0.6 million and $1.7 million were allocated to financing activities, respectively.

As a result of the adoption of IFRS 16, the Company has revised its accounting policy for leases as follows:

A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. A lease obligation and corresponding Leased asset are recognized at the commencement of the lease. Lease liabilities are initially measured at the present value of the unavoidable lease payments and discounted using the Company's incremental borrowing rate when an implicit rate in the lease is not readily available. Interest expense is recognized on the lease obligations using the effective interest rate method. The Leased asset is recognized at the amount of the lease liability, adjusted for lease incentives received and initial direct costs, on commencement of the lease. The Leased asset is depreciated on a straight-line basis over the lease term. The Company is required to make judgments and assumptions on incremental borrowing rates and lease terms. The carrying balance of the Leased assets and lease liabilities, and related interest and depreciation expense, may differ due to changes in market conditions and expected lease terms.

ADVISORIES AND OTHER GUIDANCE

Non-GAAP Financial Measures

The "Adjusted Funds Flow", "Light Oil Operating Income", "Light Oil Operating Netback", "Light Oil Capital Expenditures Net of Capital-Carry", "Thermal Oil Operating Income (Loss)", "Thermal Oil Operating Netback", "Consolidated Operating Income (Loss)", "Consolidated Operating Netback", "Consolidated Capital Expenditures Net of Capital-Carry" and "Consolidated Free Cash Flow" financial measures contained in this MD&A do not have standardized meanings which are prescribed by IFRS and they are considered to be non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers and should not be considered in isolation with measures that are prepared in accordance with IFRS.

The following table reconciles cash flow from operating activities in the consolidated financial statements for the three and nine months ended September 30, 2019 and 2018 to Adjusted Funds Flow:

	Three months ended September 30,		Nine months ended September 30,	
($ Thousands)	**2019**	**2018**	**2019**	**2018**
Cash flow from operating activities(1)	$ 16,741	$ 61,733	$ 59,657	$ 86,097
Changes in non-cash working capital	26,860	(624)	70,339	(22,281)
Settlement of provisions	305	932	3,286	5,078
Long-term deposits	—	110	—	12,577
ADJUSTED FUNDS FLOW(1)	$ 43,906	$ 62,151	$ 133,282	$ 81,471

(1) For the three and nine months ended September 30, 2019, the adoption of IFRS 16 *Leases* resulted in a $0.6 million and $1.7 million increase in cash flow from operating activities and Adjusted Funds Flow, respectively.

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 and Light Oil Operating Netback measures in this MD&A are calculated by subtracting royalties, operating expenses and transportation & marketing expenses from petroleum and natural gas sales. The Light Oil Operating Netback measure is presented on a per boe basis. The Light Oil Operating Income 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 to *Note 12 - Segmented Information* in the consolidated financial statements for the three and nine months ended September 30, 2019.

The Operating Income (Loss) and Operating Netback measures in this MD&A with respect to the Leismer Project and Hangingstone Project are calculated by subtracting the cost of diluent blending, royalties, operating expenses and transportation & marketing expenses from blended bitumen sales. The Thermal Oil Operating Netback measure is presented on a per barrel basis of bitumen sales. 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 12 - Segmented Information* in the consolidated financial statements for the three and nine months ended September 30, 2019.

The Consolidated Operating Income (Loss) and Consolidated Operating Netback measures in this MD&A are calculated by adding or subtracting realized gains (losses) on commodity risk management contracts, royalties, the cost of diluent blending, operating expenses and transportation & marketing expenses from petroleum and natural gas sales. The Consolidated Operating Netback measure is 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 12 - Segmented Information* in the consolidated financial statements for the three and nine months ended September 30, 2019.

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.

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

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. Athabasca confirms that no material weaknesses or such changes were identified in Athabasca's internal controls over financial reporting during the third quarter of 2019.

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;
- 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;
- 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; and
- Athabasca's information and computer systems and exposure to cyber-security breaches.

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; the benefits expected to be realized by the Company from the 2022 Notes and the Credit Facility; the benefits expected to be realized by the Company from the Leismer/Corner acquisition; the timing by which the Corporation expects to achieve sustainable free cash flow generation, cash and cash equivalents and liquidity, for certain future periods; expectations with respect to future production hedging levels; estimates of corporate, Thermal Oil and Light Oil production levels and base decline rates; the in-service dates of the Trans Mountain pipeline expansion and TC Energy Keystone XL pipeline and the benefits Athabasca expects to realize by having capacity thereon; estimates of Adjusted Funds Flow, Operating Income and capital expenditures; the capability of the Company's future development outlook to deliver potential growth in per share production; the estimated impact of the Royalty on the economics of future expansion phases and development projects; future drilling and completion plans; production growth and future operating expenses; the timing of well spudding and completion operations and wells coming on-stream; the Company's expected flexibility in its pace of development; the Company's plans for, and results of, exploration and development activities; the Company's estimated future commitments; Athabasca's continued balance-sheet strength; the Company's business and financing plans and strategies; expectations regarding the capital budget; the Company's anticipated sources of funding for 2019 and beyond; the Company's estimate future minimum capital commitments; the future allocation of capital; and other matters.

Information relating to "reserves" is also deemed to be forward-looking information, as it involves the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future.

With respect to forward-looking information contained in this MD&A, assumptions have been made regarding, among other things: that Athabasca and its security holders will obtain the anticipated benefits from the 2022 Notes and the Credit Facility; 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; prices, markets and marketing; adverse changes in general economic and market conditions; climate change; political uncertainty & terrorist attacks; regulatory; gathering and processing, facilities, pipeline systems and rail; statutes and regulations regarding the environment; anticipated benefits of acquisitions and dispositions; abandonment and reclamation costs; ability to finance; state of the capital markets; stage of development; royalty regimes; additional funding requirements; foreign exchange rates and interest rates; uncertainties inherent in estimating reserves and resources volumes; hedging; operational dependence; diluent supply; operating costs; hydraulic fracturing; future acquisition and joint venture activities; exploration, development and production risks; third party credit risk; conflicts of interest; aboriginal claims; reliance on key personnel and operators; financial assurances; inability to utilize the most advanced technologies; changing demand for oil and natural gas products; tax reassessments or changes to income tax laws; need to replace reserves; environmental and health and safety risks and hazards; management estimates and assumptions; liability management; seasonality and weather conditions; unexpected events; internal controls; insurance; litigation; natural gas overlying bitumen resources; competition; chain of title; breaches of confidentiality; new industry related activities or new geographical areas; cyber-security; risks related to our indebtedness; risks related to the common shares.

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, 2018 (which is respectively referred to herein as the "McDaniel Report”).

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, 2018. 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 figures described herein have been rounded to the nearest MMbbl or MMboe. Contingent Resources described herein have been rounded to the nearest billion barrels. 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 1,000 Duvernay drilling locations referenced on page 6 of this MD&A include: 50 proved undeveloped or non-producing locations and 35 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 12 probable undeveloped locations for a total of 89 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, 2018 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, 2018, 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 TransCanada 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