Management's Discussion and Analysis

Q3 2018

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 7, 2018 and should be read in conjunction with the audited consolidated financial statements of the Company for the years ended December 31, 2017 and 2016 and the unaudited condensed interim consolidated financial statements of the Company for the three and nine months ended September 30, 2018. These financial statements, including the comparative figures, were prepared in accordance with International Financial Reporting Standards ("IFRS"). This MD&A contains forward looking information based on the Company's current expectations and projections. For information on the material factors and assumptions underlying such forward looking information, refer to the "Advisories and Other Guidance" section within this MD&A. Also see the "Advisories and Other Guidance" section within this MD&A for important information regarding the Company's reserves and resource information and abbreviations included in this MD&A. Additional information relating to Athabasca is available on SEDAR at www.sedar.com, including the Company's most recent Annual Information Form dated March 7, 2018 ("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 improving 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 Growth
- 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 growth potential. The Company will continue its strategic emphasis on generating strong margins to maximize shareholder return and generate free cash flow into the future.

HIGHLIGHTS FOR THE QUARTER ENDED SEPTEMBER 30, 2018

Corporate

- Third quarter 2018 production of 40,612 boe/d, an increase of 12% over the prior year.
- Strong oil-weighted margins with 88% of production and 97% of revenues in the third quarter generated from high value liquids.
- Third quarter 2018 Consolidated Operating Income(1) of $83.7 million with a Consolidated Operating Netback of $23.21/boe.
- Record third quarter 2018 Adjusted Funds Flow(1) of $62.2 million.
- Strong balance sheet position with funding capacity of approximately $356 million, including $128 million of cash and cash equivalents, $127 million of available credit and letter of credit facilities and a $101 million (undiscounted) capital-carry balance.

Light Oil Division

- Production of 10,135 boe/d for the third quarter of 2018, representing growth of 29% over the prior year.
- Third quarter 2018 Operating Netback(1) of $31.95/boe with low operating expenses of $7.52/boe.
- Operating Income(1) of $29.8 million in the third quarter of 2018, up 117% relative to the prior year.
- Twenty-six (gross) wells placed on production year to date, including five (gross) wells at Greater Placid and twenty-one (gross) wells at Greater Kaybob.

Thermal Oil Division

- Third quarter 2018 production of 30,477 bbl/d, an 8% increase compared to the third quarter of 2017.
- Third quarter 2018 Operating Netback(1) of $23.30/bbl; 25% reduction in year over year non-energy operating expenses.
- Record Operating Income(1) of $62.3 million in the third quarter of 2018, up 78% relative to the prior year.
- Successfully installed a fifth steam generator and brought four infill wells on-stream at Leismer.

(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)[1]	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
CONSOLIDATED				
Petroleum and natural gas volumes (boe/d)	40,612	36,133	39,614	33,183
Operating Income[1][2]	$ 83,703	$ 52,358	$ 147,298	$ 115,346
Operating Netback[1][2] ($/boe)	$ 23.21	$ 15.59	$ 13.60	$ 12.73
Capital expenditures[3]	$ 74,509	$ 73,833	$ 210,929	$ 209,630
Capital Expenditures Net of Capital-Carry[1][3]	$ 52,389	$ 67,741	$ 147,938	$ 179,365
LIGHT OIL DIVISION				
Oil, condensate and natural gas liquids (bbl/d)	5,167	4,282	5,382	3,446
Natural gas (Mcf/d)	29,811	21,556	32,698	16,504
Petroleum and natural gas volumes (boe/d)	10,135	7,875	10,832	6,197
Operating Income[1]	$ 29,795	$ 13,748	$ 85,023	$ 37,001
Operating Netback[1] ($/boe)	$ 31.95	$ 18.98	$ 28.76	$ 21.87
Capital expenditures	$ 60,739	$ 53,406	$ 152,926	$ 162,113
Capital Expenditures Net of Capital-Carry[1]	$ 38,619	$ 47,314	$ 89,935	$ 131,848
THERMAL OIL DIVISION				
Bitumen production (bbl/d)	30,477	28,258	28,782	26,986
Operating Income[1]	$ 62,322	$ 34,945	$ 95,213	$ 71,654
Operating Netback[1] ($/bbl)	$ 23.30	$ 13.27	$ 12.10	$ 9.73
Capital expenditures[3]	$ 13,767	$ 20,382	$ 57,993	$ 45,376
CASH FLOW AND FUNDS FLOW				
Cash flow from operating activities	$ 61,733	$ 49,488	$ 86,097	$ 24,637
per share (basic)	$ 0.12	$ 0.10	$ 0.17	$ 0.05
Adjusted Funds Flow[1]	$ 62,151	$ 34,400	$ 81,471	$ 60,315
per share (basic)	$ 0.12	$ 0.07	$ 0.16	$ 0.12
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)				
Net income (loss) and comprehensive income (loss)	$ 31,419	$ 5,113	$ (81,178)	$ 181
per share (basic and diluted)	$ 0.06	$ 0.01	$ (0.16)	$ —
COMMON SHARES OUTSTANDING				
Weighted average shares outstanding - basic	515,792,185	509,335,251	513,575,091	496,845,215
Weighted average shares outstanding - diluted	527,414,170	513,332,423	513,575,091	502,283,110

As at ($ Thousands)	September 30, 2018	December 31, 2017
LIQUIDITY AND BALANCE SHEET		
Cash and cash equivalents	$ 128,340	$ 163,321
Restricted cash	$ 114,216	$ 113,406
Available credit facilities[4]	$ 59,991	$ 61,899
Capital-carry receivable (current and long-term portion - undiscounted)	$ 101,031	$ 164,023
Face value of long-term debt[5]	$ 581,558	$ 563,310

(1) Refer to the “Advisories and Other Guidance” section within this MD&A for additional information on Non-GAAP Financial Measures.
(2) Includes realized gain (loss) on commodity risk management contracts of $(8.4) million and $(32.9) million for the three and nine months ended September 30, 2018, respectively ($3.7 million and $6.7 million for the three and nine months ended September 30, 2017, respectively).
(3) 2017 capital expenditures excludes the cost of the Leismer Corner Acquisition (see page 9).
(4) Subsequent to September 30, 2018 Athabasca's available credit and letter of credit facilities increased to $127 million.
(5) The face value of the 2022 Notes is US$450 million. The 2022 Notes were translated into Canadian dollars at the September 30, 2018 exchange rate of US$1.00 = C$1.2924.

BUSINESS ENVIRONMENT

The global crude outlook remains supported by strong demand, low inventories, ongoing geopolitical risk and a decrease in spare productive capacity. Athabasca is a beneficiary with its oil-weighted portfolio.

Despite the strong global crude outlook, Canadian producers have experienced unprecedented differential volatility across light and heavy product streams due to pipeline capacity constraints and refinery turnarounds in key consuming US regions.

The Company anticipates differentials to remain wider than historical levels through the winter. Athabasca has responded to widening differentials by strategically slowing production by 5,000 - 8,000 bbl/d for the balance of the year (November and December) at Hangingstone and Leismer to optimize netbacks with no long term impacts to the reservoirs.

WCS differentials are expected to normalize between US$18 - US$24/bbl over the mid-term supported by a resumption in refinery demand (~1.5 MMbbl/d of peak outages), mobilization of industry crude by rail (currently ~300,000 bbl/d), producer curtailments and Enbridge's Line 3 Replacement project (370,000 bbl/d). The US refinery complex has made significant investments over the past decade to increase processing capacity of heavy feedstock. Canadian heavy production is expected to have an increasing market share offsetting declines in Venezuela and Mexico.

Athabasca also continues to optimize netback performance by mitigating apportionment with sales to refineries (~60% in the third quarter of 2018) and through access to leased storage in Edmonton. Athabasca has secured long term egress to multiple end markets with 25,000 bbl/d of capacity on the TransCanada Keystone XL pipeline and 20,000 bbl/d of capacity on the Trans Mountain pipeline expansion.

The Company is a net consumer of gas and is a beneficiary of the low Alberta gas pricing environment.

The following table highlights the benchmark prices that are the most relevant to Athabasca's realized pricing. Athabasca's realized pricing will also reflect quality differentials relative to the benchmark prices.

Benchmark prices

	Three months ended September 30,			Nine months ended September 30,		
(Average)	2018	2017	Change	2018	2017	Change
Crude oil:						
West Texas Intermediate (WTI) (US$/bbl)[1]	$ 69.50	$ 48.21	44 %	$ 66.75	$ 49.47	35 %
West Texas Intermediate (WTI) (C$/bbl)[1]	$ 90.84	$ 60.35	51 %	$ 85.93	$ 64.65	33 %
Western Canadian Select (WCS) (C$/bbl)[2]	$ 61.75	$ 47.76	29 %	$ 57.76	$ 49.02	18 %
Edmonton Par (C$/bbl)[3]	$ 81.90	$ 56.62	45 %	$ 78.23	$ 60.78	29 %
Edmonton Condensate (C5+) (C$/bbl)[4]	$ 87.01	$ 59.01	47 %	$ 84.69	$ 64.10	32 %
WCS Differential:						
WTI vs. WCS (US$/bbl)	$ (22.25)	$ (10.00)	(123)%	$ (21.93)	$ (12.05)	(82)%
WTI vs. WCS (C$/bbl)	$ (29.09)	$ (12.59)	(131)%	$ (28.17)	$ (15.63)	(80)%
Edmonton Par Differential:						
WTI vs. Edmonton Par (US$/bbl)	$ (6.83)	$ (2.91)	(135)%	$ (6.06)	$ (3.07)	(97)%
WTI vs. Edmonton Par (C$/bbl)	$ (8.94)	$ (3.73)	(140)%	$ (7.70)	$ (3.87)	(99)%
Natural gas:						
AECO (C$/GJ)[5][6]	$ 1.13	$ 1.38	(18)%	$ 1.41	$ 2.19	(36)%
NYMEX Henry Hub (US$/MMBtu)[6]	$ 2.91	$ 3.00	(3)%	$ 2.90	$ 3.17	(9)%
Foreign exchange:						
USD : CAD	1.31	1.25	5 %	1.29	1.31	(2)%

Primary benchmark for:

(1) Crude oil pricing in North America.
(2) Athabasca's blended bitumen sales. WCS trades at a wider differential to the WTI price compared to lighter crude oil products.
(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 which Athabasca utilizes in the blending process 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.

OUTLOOK

2018 Operational & Financial Guidance ($ millions, unless otherwise noted)	Full year
Corporate (net)	
Production (boe/d)	39,000 - 41,000
Capital expenditures(1)	$200
Adjusted Funds Flow(2)	$55
Commodity assumptions	
WTI (US$/bbl)	$67.50
WCS differential (US$/bbl)	$26.50
AECO Gas (C$/Mcf)	$1.55
FX (US$/C$)	0.77

(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.

Athabasca's 2018 capital budget is $200 million and includes $85 million in Thermal Oil and $115 million in Light Oil ($85 million Greater Placid and $30 million net Greater Kaybob).

In Greater Placid, the Company recently completed a six well development pad (surface location 12-19-60-23W5) which is being tied into permanent facilities. Drilling is also underway on a seven well development pad (surface location 16-30-60-23W5). In light of current differential volatility and a focus on maximizing shareholder returns, the Company has elected to temporarily defer completion operations. In Greater Kaybob, activity remains robust with the joint venture partnership executing an annual budget of C$387 million (C$30 million net) in 2018 which includes completion operations on 24 wells and placing 26 wells on production. In Thermal Oil, the Company has commenced operations on the next sustaining pad (Pad L7) at Lesimer with drilling to be completed this winter and on-stream in the second half of 2019. Project capital for Pad L7 is approximately $55 million with the majority of capital allocated to 2019.

The Company anticipates achieving its prior annual guidance of 39,000 - 41,000 boe/d despite the temporary production curtailments in Thermal Oil for the remainder of the year.

Athabasca's priority is to maintain balance street strength by aligning 2019 activity levels to forecasted cash flow and the Company is prepared to implement a minimal capital program until Canadian differentials improve. Growth projects beyond this level will be evaluated in the context of maintaining financial flexibility, corporate free cash flow and external market conditions. Athabasca has significant flexibility in capital allocation. Thermal Oil underpins a low corporate decline of approximately 10% and provides shareholders free cash flow torque to normalizing differentials and strengthening global oil fundamentals. Placid Montney bolsters the Company's exposure to high netback production with a flexible development. Kaybob Duvernay is self-funded with minimal capital exposure to the end of 2019 through a joint venture and also increases the Company's exposure to high value condensate production.

Athabasca's available funding capacity is estimated at $356 million including cash & cash equivalents, Duvernay capital carry and available credit facilities.

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 within this MD&A.

Consolidated Operating Results

	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
VOLUMES				
Oil and condensate (bbl/d)	4,201	3,945	4,341	3,124
Natural gas (Mcf/d)	29,811	21,556	32,698	16,504
Natural gas liquids (bbl/d)	966	337	1,041	322
Bitumen production (bbl/d)	30,477	28,258	28,782	26,986
Total (boe/d)	40,612	36,133	39,614	33,183

($ Thousands, unless otherwise noted)	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Petroleum and natural gas sales	$ 253,404	$ 187,722	$ 712,752	$ 545,198
Royalties	(7,272)	(3,180)	(15,824)	(7,941)
Cost of diluent	(96,779)	(73,080)	(325,504)	(244,131)
Operating expenses	(38,503)	(45,263)	(129,194)	(132,648)
Transportation and marketing	(18,733)	(17,506)	(61,994)	(51,823)
	$ 92,117	$ 48,693	$ 180,236	$ 108,655
Realized gain (loss) on commodity risk management contracts	(8,414)	3,665	(32,938)	6,691
Consolidated Operating Income(1)	$ 83,703	$ 52,358	$ 147,298	$ 115,346
REALIZED PRICES				
Oil and condensate ($/bbl)	$ 81.81	$ 55.24	$ 78.21	$ 58.10
Natural gas ($/Mcf)	2.57	2.82	2.69	3.54
Natural gas liquids ($/bbl)	52.22	29.70	52.48	24.44
Blended bitumen sales ($/bbl)	57.76	44.76	52.07	46.05
Realized price (net of cost of diluent) ($/boe)	43.42	34.13	35.76	33.24
Royalties ($/boe)	(2.02)	(0.95)	(1.46)	(0.88)
Operating expenses ($/boe)	(10.67)	(13.47)	(11.93)	(14.65)
Transportation and marketing ($/boe)	(5.19)	(5.21)	(5.73)	(5.72)
	$ 25.54	$ 14.50	$ 16.64	$ 11.99
Realized gain (loss) on commodity risk management contracts ($/boe)	(2.33)	1.09	(3.04)	0.74
CONSOLIDATED OPERATING NETBACK(1) ($/boe)	$ 23.21	$ 15.59	$ 13.60	$ 12.73

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

Consolidated Segments Income

($ Thousands)	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Consolidated Operating Income(1)	$ 83,703	$ 52,358	$ 147,298	$ 115,346
Unrealized gain (loss) on commodity risk management contracts	17,302	(13,169)	7,468	2,288
Depletion and depreciation	(41,981)	(27,807)	(120,929)	(75,222)
Acquisition expense	—	—	—	(11,047)
Loss on sale of assets	—	—	—	(372)
Exploration expense and other	(331)	(48)	(792)	(306)
CONSOLIDATED SEGMENTS INCOME	$ 58,693	$ 11,334	$ 33,045	$ 30,687

(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, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Light Oil Division	$ 60,739	$ 53,406	$ 152,926	$ 162,113
Thermal Oil Division[1]	13,767	20,382	57,993	45,376
Corporate assets	3	45	10	2,141
TOTAL CAPITAL EXPENDITURES[2]	$ 74,509	$ 73,833	$ 210,929	$ 209,630
Less: Greater Kaybob capital-carry	(22,120)	(6,092)	(62,991)	(30,265)
TOTAL CAPITAL EXPENDITURES NET OF CAPITAL-CARRY[3]	$ 52,389	$ 67,741	$ 147,938	$ 179,365

(1) 2017 Thermal Oil capital expenditures in the table above exclude the cost of the Leismer Corner Acquisition (as defined on page 9).
(2) For the three and nine months ended September 30, 2018, capital expenditures include $2.8 million and $9.0 million of capitalized staff costs, respectively (September 30, 2017 - $3.5 million, $9.4 million).
(3) 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 and Duvernay in the Greater Placid and Greater Kaybob areas near the town of Fox Creek, Alberta.

In 2016, Athabasca entered into a joint venture with Murphy Oil Company Ltd. ("Murphy") to advance development of its Light Oil assets (the "Murphy Transaction") which resulted in Athabasca holding an operated 70% working interest in its Greater Placid assets and a non-operated 30% working interest in its Greater Kaybob assets. Included as part of the transaction consideration was a $219.0 million (undiscounted) capital-carry commitment in Greater Kaybob, under which Murphy is obligated to fund 75% of Athabasca's share of development capital for up to a maximum five year period. The carry supports approximately $1 billion of Duvernay investment with Athabasca's financial exposure limited to $75 million to retain its 30% working interest. The capital-carry balance remaining at September 30, 2018 is $101.0 million (undiscounted).

In Greater Placid, Athabasca has an operated position in approximately 80,000 gross Montney acres. An inventory of over 200[1] high-graded gross drilling locations positions the Company for multi-year growth in this area. Athabasca also has a 30% non-operated interest in over 200,000 gross acres of commercially prospective Duvernay lands in Greater Kaybob with exposure to both liquids-rich gas and volatile oil opportunities and an inventory of approximately 1,000[1] gross drilling locations. Athabasca's Light Oil Division assets are supported by jointly-owned 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. As at December 31, 2017, the Light Oil Division had approximately 77 MMboe of Proved plus Probable Reserves[2].

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information regarding the Company's drilling locations.
(2) Based on the report of Athabasca's independent reserve evaluator effective December 31, 2017. 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.

Light Oil Operating Results

	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
SALES VOLUMES				
Oil and condensate (bbl/d)	4,201	3,945	4,341	3,124
Natural gas (Mcf/d)	29,811	21,556	32,698	16,504
Natural gas liquids (bbl/d)	966	337	1,041	322
Total (boe/d)	10,135	7,875	10,832	6,197
Consisting of:				
Greater Placid area (boe/d)	5,837	6,155	7,554	4,676
% liquids	42%	51%	44%	54%
Greater Kaybob area (boe/d)	4,298	1,720	3,278	1,521
% liquids	63%	66%	63%	60%

($ Thousands, unless otherwise noted)	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Petroleum and natural gas sales	$ 43,294	$ 26,680	$ 131,583	$ 67,666
Royalties	(1,771)	(2,194)	(4,729)	(3,854)
Operating expenses	(7,012)	(7,682)	(25,494)	(17,837)
Transportation and marketing	(4,716)	(3,056)	(16,337)	(8,974)
Light Oil Operating Income[(1)]	$ 29,795	$ 13,748	$ 85,023	$ 37,001
REALIZED PRICES				
Oil and condensate ($/bbl)	$ 81.81	$ 55.24	$ 78.21	$ 58.10
Natural gas ($/Mcf)	2.57	2.82	2.69	3.54
Natural gas liquids ($/bbl)	52.22	29.70	52.48	24.44
Realized price ($/boe)	46.43	36.83	44.50	39.99
Royalties ($/boe)	(1.90)	(3.03)	(1.60)	(2.28)
Operating expenses ($/boe)	(7.52)	(10.60)	(8.62)	(10.54)
Transportation and marketing ($/boe)	(5.06)	(4.22)	(5.52)	(5.30)
LIGHT OIL OPERATING NETBACK[(1)] ($/boe)	$ 31.95	$ 18.98	$ 28.76	$ 21.87

(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 10,135 boe/d during the third quarter of 2018, an increase of 29% compared to the third quarter of 2017. During the first nine months of 2018 production averaged 10,832 boe/d, an increase of 75%. Production growth year over year was primarily a result of continued development with 21 (gross) Montney and 32 (gross) Duvernay wells tied-in throughout 2017 and the first nine months of 2018, partially offset by lower Greater Placid production in the third quarter of 2018 due to the planned shut-in of offset wells during completion operations.

Athabasca's Light Oil Operating Netbacks were $31.95/boe and $28.76/boe during the three and nine months ended September 30, 2018, increases of 68% and 32%, respectively, from the comparable 2017 periods. These netback increases have been driven by higher average realized pricing with stronger WTI prices in 2018 more than offsetting the higher Edmonton Par differentials and the lower prices for natural gas. Athabasca's Light Oil netback is supported by high liquids margins with 84% of third quarter 2018 revenues generated from oil, condensate and natural gas liquids. Operating expenses per boe in the 2018 periods have decreased relative to the prior year periods as a result of significantly higher production and a continued emphasis on operational efficiencies.

As a result of higher production and higher netbacks, Athabasca generated Light Oil Operating Income of $29.8 million in the third quarter of 2018 and $85.0 million in the first nine months of 2018, up 117% and 130%, respectively, from the comparable 2017 periods.

Light Oil Segment Income

($ Thousands)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Light Oil Operating Income[(1)]	$ 29,795	$ 13,748	$ 85,023	$ 37,001
Depletion and depreciation	(16,613)	(10,003)	(52,413)	(24,794)
Loss on sale of assets	—	—	—	(101)
Exploration expense and other	(35)	(31)	(40)	(77)
LIGHT OIL SEGMENT INCOME	$ 13,147	$ 3,714	$ 32,570	$ 12,029

(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 $6.6 million in the third quarter of 2018 and $27.6 million in the first nine months of 2018, compared to the same periods in the prior year, primarily due to higher production volumes.

Light Oil Capital Expenditures

($ Thousands)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Greater Placid				
Drilling, completion and equipping	$ 29,066	$ 37,915	$ 62,986	$ 88,384
Facilities	1,042	6,094	2,586	28,811
Other	1,238	953	4,206	5,613
	31,346	44,962	69,778	122,808
Greater Kaybob				
Drilling, completion and equipping	27,468	7,638	74,590	37,826
Facilities	1,742	418	8,518	1,099
Other	183	388	40	380
	29,393	8,444	83,148	39,305
TOTAL LIGHT OIL CAPITAL EXPENDITURES[(1)]	$ 60,739	$ 53,406	$ 152,926	$ 162,113
Less: Greater Kaybob capital-carry	(22,120)	(6,092)	(62,991)	(30,265)
TOTAL CAPITAL EXPENDITURES NET OF CAPITAL-CARRY[(2)]	$ 38,619	$ 47,314	$ 89,935	$ 131,848

(1) For the three and nine months ended September 30, 2018, capital expenditures include $1.2 million and $3.8 million of capitalized staff costs, respectively (September 30, 2017 - $1.4 million, $4.4 million).
(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

The following table summarizes Athabasca's well activity for the three and nine months ended September 30, 2018 and 2017:

	Three months ended September 30,				Nine months ended September 30,			
	2018		2017		2018		2017	
Well activity[(1)]	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Greater Placid								
Wells drilled	2	1.4	—	—	8	5.6	10	7.0
Wells completed	6	4.2	8	5.6	11	7.7	17	11.9
Wells brought on production	—	—	3	2.1	5	3.5	11	7.7
Greater Kaybob								
Wells drilled	7	2.1	2	0.6	23	6.9	9	2.7
Wells completed	5	1.5	—	—	19	5.7	7	2.1
Wells brought on production	11	3.3	3	0.9	21	6.3	7	2.1

(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.

In the third quarter of 2018, Athabasca commenced the drilling of a multi-well development pad as a part of its 2018/19 winter drilling program and completed a six-well pad in Greater Placid which will be brought on production in the fourth quarter of 2018. In aggregate, in Greater Placid, the Company has rig released eight (gross) wells, completed eleven (gross) wells and brought on production five (gross) wells in the first nine months of 2018.

In Greater Kaybob, seven (gross) wells were rig released, five (gross) wells were completed and eleven (gross) wells were brought on production in the third quarter of 2018. In total, twenty-three (gross) wells were rig released, nineteen (gross) wells were completed and twenty-one (gross) wells were brought on production in the first nine months of 2018. Including recovery of the capital-carry, Athabasca's net cash outflow from capital expenditures in Greater Kaybob was $7.3 million and $20.2 million for the three and nine months ended September 30, 2018, respectively.

THERMAL OIL DIVISION

Overview

Athabasca's Thermal Oil Division consists of two operating oil sands projects and a large resource base of expansion and exploration areas in the Athabasca region of northeastern Alberta.

On January 31, 2017, Athabasca completed the acquisition of Canadian oil sands assets from Statoil Canada Ltd. and its wholly-owned affiliate KKD Oil Sands Partnership, both subsidiaries of Equinor (formally Statoil ASA; collectively "Equinor"). The acquired assets include the operating Leismer Thermal Oil Project (the "Leismer Project"), the delineated Corner lease and related strategic infrastructure (the "Leismer Corner Acquisition"). The acquisition had an effective date of January 1, 2017.

The Leismer Project was commissioned in 2010 and has proven reserves in place to support a flat production profile for over 30 years and a reserve life index of approximately 85 years (proved plus probable). The Leismer Project has Proved plus Probable Reserves of approximately 657 MMbbl[1] and 0.3 billion barrels (risked)[1] (0.3 billion barrels unrisked)[1] of Best Estimate pending Contingent Resources. The Corner lease has Proved plus Probable Reserves of approximately 331 MMbbl[1] and 0.4 billion barrels (risked)[1] (0.5 billion barrels unrisked)[1] of Best Estimate 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.

Strategic infrastructure acquired as part of the acquisition includes ownership of dilbit and diluent pipelines from Leismer to the Cheecham Terminal and 300,000 barrels of storage capacity at the Cheecham Terminal. Athabasca also acquired access to multiple sales points with marketing agreements on the Enbridge Waupisoo transportation pipeline. 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 TransCanada Keystone XL pipeline which will provide the Company with long term access to multiple end markets.

Consideration for the transaction included cash of $435.9 million and the issuance of 100 million common shares which were valued at $166.0 million. Athabasca also agreed to a series of annual contingent payments which are only triggered at oil prices above US $65/bbl WTI for a four year term ending in 2020. Each annual payment is calculated on one-third of the Leismer Project bitumen production multiplied by an oil price factor (yearly average US$WTI/bbl less US$65/bbl, adjusted for inflation). The payments are capped at $75.0 million annually over the remaining three year term. As at September 30, 2018, the estimated obligation with respect to 2018 was $5.9 million. No amounts were paid by Athabasca with respect to the annual contingent payment obligation for 2017.

Athabasca also operates the Hangingstone Thermal Oil Project (the “Hangingstone Project"). Hangingstone has Proved plus Probable Reserves of approximately 181 MMbbl[1].

Athabasca's other Thermal Oil exploration areas consist of Dover West Leduc Carbonates, Dover West Sands, Birch and Grosmont. Future development targets include oil sands in the McMurray and Wabiskaw formations as well as carbonates in the Leduc formation.

In 2016 and 2017, Athabasca granted Contingent Bitumen Royalties (the "Royalty") on its Thermal Oil assets to Burgess Energy Holdings L.L.C. ("Burgess") for gross cash proceeds of $397.0 million. Under the terms of the Royalty, Athabasca will pay Burgess a linear-scale Royalty of 0% - 12%, relative to a WCS benchmark price, applied to Athabasca’s realized bitumen price (C$), which is determined net of diluent, transportation and storage costs. No amounts have been paid or are currently payable in respect of the Royalty to Burgess.

The following table summarizes the Royalty rates applicable at different WCS benchmark prices:

Hangingstone, Leismer and Corner WCS benchmark price (US$/bbl)	Royalty rate
Below $60/bbl	--
$60/bbl to $139.99/bbl	2% - 12%
$140/bbl and above	12%

Dover West, Birch and Grosmont WCS benchmark price (US$/bbl)	Royalty rate
Below $70/bbl	--
$70/bbl to $149.99/bbl	2% - 12%
$150/bbl and above	12%

(1) Based on the report of Athabasca's independent reserve evaluator effective December 31, 2017. 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,		Nine months ended September 30,	
	2018	2017	2018	2017
VOLUMES[1]				
Bitumen production (bbl/d)	20,975	19,498	19,469	18,259
Bitumen sales (bbl/d)	21,026	19,943	19,652	18,226
Blended bitumen sales (bbl/d)	28,199	27,203	27,521	25,729

	Three months ended September 30,		Nine months ended September 30,	
($ Thousands, unless otherwise noted)	2018	2017	2018	2017
Blended bitumen sales	$ 147,976	$ 111,435	$ 383,984	$ 324,007
Cost of diluent	(66,852)	(51,107)	(215,716)	(166,209)
Total bitumen sales	81,124	60,328	168,268	157,798
Royalties	(4,040)	(691)	(7,979)	(2,877)
Operating expenses - non-energy	(12,937)	(16,695)	(40,103)	(45,379)
Operating expenses - energy	(5,246)	(5,076)	(16,277)	(17,681)
Transportation and marketing	(5,604)	(5,237)	(16,203)	(14,105)
Leismer Operating Income[1][2]	$ 53,297	$ 32,629	$ 87,706	$ 77,756
REALIZED PRICE				
Blended bitumen sales ($/bbl)	$ 57.04	$ 44.53	$ 51.11	$ 46.13
Bitumen sales ($/bbl)	$ 41.94	$ 32.88	$ 31.36	$ 31.71
Royalties ($/bbl)	(2.09)	(0.38)	(1.49)	(0.58)
Operating expenses - non-energy ($/bbl)	(6.69)	(9.10)	(7.47)	(9.12)
Operating expenses - energy ($/bbl)	(2.71)	(2.77)	(3.03)	(3.55)
Transportation and marketing ($/bbl)	(2.90)	(2.85)	(3.02)	(2.83)
LEISMER OPERATING NETBACK[1][2] ($/bbl)	$ 27.55	$ 17.78	$ 16.35	$ 15.63

(1) The Leismer Project was acquired on January 31, 2017. The table above reflects volumes and Operating Income from February 2017 onwards for the nine months ended September 30, 2017.
(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

In the third quarter of 2018, Leismer bitumen production averaged 20,975 bbl/d, an increase of 8% compared to the third quarter of 2017. The higher production was primarily due to the start-up of four infill wells in the third quarter of 2018 and additional production from optimization activities. During the first nine months of 2018, bitumen production averaged 19,469 bbl/d, an increase of 7% from the comparable 2017 period. The production increase was primarily a result of the Leismer Corner Acquisition which was completed on January 31, 2017, partially offset by the reduced production associated with the Leismer turnaround which was completed in the second quarter of 2018.

The Leismer Operating Netback was $27.55/bbl during the third quarter of 2018 and $16.35/bbl in the first nine months of 2018, increases of 55% and 5%, respectively, from the comparable 2017 periods. The increase in the third quarter of 2018 was primarily due to higher realized pricing for bitumen sales and lower operating costs, partially offset by higher royalties. The increase for the first nine months of 2018 was primarily due to lower operating costs. Higher realized bitumen pricing in the third quarter of 2018 was primarily a result of stronger WTI prices which more than offset the increase in the WCS differentials and product basis spreads.

Total operating expenses were $9.40/bbl in the third quarter of 2018 and $10.50/bbl in the first nine months of the year, decreases of 21% and 17%, respectively, from the comparable 2017 periods. The declines were primarily due to lower non-energy operating expenses with continued efficiency gains and focus on cost management resulting in lower operating costs. For the energy operating expenses, lower natural gas prices were partially offset by increased power costs.

Leismer Operating Income was $53.3 million in the third quarter of 2018 and $87.7 million in the first nine months of 2018, up 63% and 13%, respectively, from the comparable 2017 periods.

Seasonality has an impact on the Thermal Oil business. Historically, the heavy oil differential (the price difference between WTI and WCS) tends to narrow in summer months and increase in winter months. Moving into the fourth and first quarters, the dilution costs will generally increase as more diluent is required to meet pipeline specifications.

Hangingstone Operating Results

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
VOLUMES				
Bitumen production (bbl/d)	9,502	8,760	9,313	8,727
Bitumen sales (bbl/d)	8,048	8,697	9,181	8,750
Blended bitumen sales (bbl/d)	11,342	11,906	13,365	12,259

	Three months ended September 30,		Nine months ended September 30,	
($ Thousands, unless otherwise noted)	2018	2017	2018	2017
Blended bitumen sales	$ 62,134	$ 49,607	$ 197,185	$ 153,525
Cost of diluent	(29,927)	(21,973)	(109,788)	(77,922)
Total bitumen sales	32,207	27,634	87,397	75,603
Royalties	(1,461)	(295)	(3,116)	(1,210)
Operating expenses - non-energy	(9,035)	(12,000)	(33,733)	(36,394)
Operating expenses - energy	(4,273)	(3,810)	(13,587)	(15,357)
Transportation and marketing	(8,413)	(9,213)	(29,454)	(28,744)
Hangingstone Operating Income (Loss)(1)	$ 9,025	$ 2,316	$ 7,507	$ (6,102)
REALIZED PRICE				
Blended bitumen sales ($/bbl)	$ 59.55	$ 45.29	$ 54.04	$ 45.87
Bitumen sales ($/bbl)	$ 43.50	$ 34.54	$ 34.87	$ 31.65
Royalties ($/bbl)	(1.97)	(0.37)	(1.24)	(0.51)
Operating expenses - non-energy ($/bbl)	(12.20)	(15.00)	(13.46)	(15.24)
Operating expenses - energy ($/bbl)	(5.77)	(4.76)	(5.42)	(6.43)
Transportation and marketing ($/bbl)	(11.36)	(11.51)	(11.75)	(12.03)
HANGINGSTONE OPERATING NETBACK(1) ($/bbl)	$ 12.20	$ 2.90	$ 3.00	$ (2.56)

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

In the third quarter of 2018, Hangingstone bitumen production averaged 9,502 bbl/d, an increase of 8% compared to the third quarter of 2017. During the first nine months of 2018, bitumen production averaged 9,313 bbl/d, an increase of 7% from the comparable 2017 period. Production growth year over year was associated to continued steam chamber development of the project.

The Hangingstone Operating Netback was $12.20/bbl in the third quarter of 2018 compared to $2.90/bbl during the same period in 2017. For the first nine months of 2018 the Operating Netback was $3.00/bbl compared to $(2.56)/bbl during the same period in 2017. The increases were primarily due to higher realized pricing for bitumen sales and lower total operating expenses. Higher realized bitumen pricing was primarily a result of stronger WTI prices which more than offset the increase in the WCS differentials and product basis spreads.

Total operating expenses were $17.97/bbl in the third quarter of 2018 and $18.88/bbl in the first nine months of 2018, decreases of 9% and 13%, respectively, from the comparable 2017 periods. The declines were primarily due to lower non-energy operating expenses with increased operational efficiencies and the continued focus on cost management resulting in lower operating costs. Energy operating expenses were experiencing lower natural gas prices combined with increased power costs.

Hangingstone Operating Income was $9.0 million in the third quarter of 2018 and $7.5 million in the first nine months of 2018, up $6.7 million and $13.6 million, respectively, from the comparable 2017 periods.

Seasonality has an impact on the Thermal Oil business. Historically, the heavy oil differential (the price difference between WTI and WCS) tends to narrow in summer months and increase in winter months. Moving into the fourth and first quarters, the dilution costs will generally increase as more diluent is required to meet pipeline specifications.

Consolidated Thermal Oil Operating Results

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
VOLUMES				
Bitumen production (bbl/d)	30,477	28,258	28,782	26,986
Bitumen sales (bbl/d)	29,074	28,640	28,833	26,976
Blended bitumen sales (bbl/d)	39,541	39,109	40,886	37,988

($ Thousands, unless otherwise noted)	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Blended bitumen sales	$ 210,110	$ 161,042	$ 581,169	$ 477,532
Cost of diluent	(96,779)	(73,080)	(325,504)	(244,131)
Total bitumen sales	113,331	87,962	255,665	233,401
Royalties	(5,501)	(986)	(11,095)	(4,087)
Operating expenses - non-energy	(21,972)	(28,695)	(73,836)	(81,773)
Operating expenses - energy	(9,519)	(8,886)	(29,864)	(33,038)
Transportation and marketing	(14,017)	(14,450)	(45,657)	(42,849)
Thermal Oil Operating Income(1)	$ 62,322	$ 34,945	$ 95,213	$ 71,654
REALIZED PRICE				
Blended bitumen sales ($/bbl)	$ 57.76	$ 44.76	$ 52.07	$ 46.05
Bitumen sales ($/bbl)	$ 42.37	$ 33.38	$ 32.48	$ 31.69
Royalties ($/bbl)	(2.06)	(0.37)	(1.41)	(0.55)
Operating expenses - non-energy ($/bbl)	(8.21)	(10.89)	(9.38)	(11.10)
Operating expenses - energy ($/bbl)	(3.56)	(3.37)	(3.79)	(4.49)
Transportation and marketing ($/bbl)	(5.24)	(5.48)	(5.80)	(5.82)
THERMAL OIL OPERATING NETBACK(1) ($/bbl)	$ 23.30	$ 13.27	$ 12.10	$ 9.73

(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, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Thermal Oil Operating Income(1)	$ 62,322	$ 34,945	$ 95,213	$ 71,654
Depletion and depreciation	(25,368)	(17,804)	(68,516)	(50,428)
Acquisition expense	—	—	—	(11,047)
Loss on sale of assets	—	—	—	(271)
Exploration expenses and other	(296)	(17)	(752)	(229)
THERMAL OIL SEGMENT INCOME	$ 36,658	$ 17,124	$ 25,945	$ 9,679

(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 $7.6 million in the third quarter of 2018 compared to the same period in the prior year, primarily due to higher bitumen production and a higher depletion rate. The increase in depletion and depreciation expense for the nine months ended September 30, 2018, compared to the same period in 2017, was primarily due to the Leismer Corner Acquisition on January 31, 2017 and the increase in the depletion rate in 2018.

Thermal Oil Capital Expenditures

($ Thousands)	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Leismer Project[1]	$ 10,134	$ 13,471	$ 48,223	$ 26,376
Hangingstone Project	2,080	5,496	7,251	16,528
Other Thermal Oil exploration	1,553	1,415	2,519	2,472
TOTAL THERMAL OIL CAPITAL EXPENDITURES[2]	$ 13,767	$ 20,382	$ 57,993	$ 45,376

(1) 2017 Thermal Oil capital expenditures in the table above exclude the cost of the Leismer Corner Acquisition.

(2) For the three and nine months ended September 30, 2018, capital expenditures include $1.6 million and $5.2 million of capitalized staff costs, respectively (September 30, 2017 - $2.1 million, $5.0 million).

Thermal Oil capital expenditures for the first nine months of 2018 included the turnaround at Leismer, the tie-in of Leismer to the Norlite diluent pipeline, installation of a fifth steam generator that was previously held in inventory, preliminary work on Pad 7 and the tie-in of four pre-drilled Leismer Pad 5 infill wells which were placed on production in the third quarter of 2018. Expenditures also included downhole pump conversions and replacements and the installation of tubing-deployed flow control devices at Leismer and Hangingstone.

CORPORATE REVIEW

Liquidity and Capital Resources

Funding

Balance sheet strength and flexibility continues to remain a key priority for Athabasca and the Company’s objective in managing capital is to maintain sufficient available reserves to meet its liquidity requirements at any point in time. The Company expects to achieve this objective by aligning capital expenditures with available funding, a commodity risk management program and by maintaining sufficient funds for anticipated short-term spending in cash, cash equivalent and short-term investment accounts as well as through available credit facilities.

As at September 30, 2018, Athabasca had $128.3 million of unrestricted cash and cash equivalents and additional funding available through the capital-carry receivable from Murphy of $101.0 million (undiscounted). The Company also had available credit of $60.0 million under its $120.0 million Credit Facility. Subsequent to September 30, 2018, the Company's available credit and letter of credit facilities increased to $126.5 million (see below) further enhancing the Company's liquidity position.

In 2018, 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. Beyond 2018, 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 state of the equity and debt capital markets.

Indebtedness

As at ($ Thousands)	September 30, 2018	December 31, 2017
2022 Notes[1]	$ 581,558	$ 563,310
Debt issuance costs	(47,081)	(45,039)
Amortization of debt issuance costs	12,028	7,935
TOTAL LONG-TERM DEBT	$ 546,505	$ 526,206

(1) As at September 30, 2018, the US dollar denominated 2022 Notes were translated into Canadian dollars at the period end exchange rate of US$1.00 = C$1.2924.

Athabasca had the following notes and credit facilities in place as at November 7, 2018:

2022 Notes

On February 24, 2017 Athabasca issued US$450.0 million (C$589.0 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. At any time prior to February 24, 2019, Athabasca has the option to redeem the 2022 Notes at the make whole redemption price set forth in the 2022 Notes indenture.

On or after February 24, 2019, 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 2018, 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, 2019, 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, 2020. 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 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.

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 3.00% to 4.00%. The Company incurs an issuance fee for letters of credit of 4.00% and a standby fee on the undrawn portion of the Credit Facility of 1.00%. As at September 30, 2018, the Company had $60.0 million of letters of credit issued and outstanding under the Credit Facility related to long-term transportation agreements.

Subsequent to September 30, 2018, the available credit under Athabasca's Credit Facility increased to $120.0 million. Athabasca had previously posted a $41.5 million letter of credit in relation to its dilbit transportation commitment on the Trans Mountain pipeline expansion. The pipeline owner has returned the letter of credit to Athabasca and will reassess the need for financial assurances, if any, closer to the pipeline completion date. Athabasca also entered into a new $25.0 million Unsecured Letter of Credit Facility (see below) during the fourth quarter and all remaining letters of credit issued under the Credit Facility were transferred to the new 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 bear 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, 2018, Athabasca had $110.0 million in letters of credit issued and outstanding under the Letter of Credit Facility, as well as $114.2 million in restricted cash that was primarily related to 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 for issuing letters of credit to counterparties and is available on a demand basis. Letters of credit issued under this facility incur an issuance and performance guarantee fee of 2.20%.

Financing and Interest

($ Thousands)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Financing and interest expense on indebtedness	$ 15,328	$ 15,075	$ 45,113	$ 45,360
Amortization of debt issuance costs	2,210	2,454	6,349	10,150
Accretion of provisions	2,903	2,913	8,609	6,985
TOTAL FINANCING AND INTEREST	$ 20,441	$ 20,442	$ 60,071	$ 62,495

During the three and nine months ended September 30, 2018 and 2017, financing and interest expenses were primarily attributable to the Company's 2022 Notes. Athabasca also incurred fees related to its Credit Facility and Letter of Credit Facility.

Foreign Exchange Gain (Loss), Net

($ Thousands)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Unrealized foreign exchange gain (loss)	$ 9,834	$ 19,699	$ (16,206)	$ 23,951
Realized foreign exchange gain (loss)	(164)	2,285	(381)	478
FOREIGN EXCHANGE GAIN (LOSS), NET	$ 9,670	$ 21,984	$ (16,587)	$ 24,429

In 2017, Athabasca became 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. 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 has entered into US dollar forward swap contracts to reduce its exposure to foreign currency risk related to its near-term interest payment.

Financial commodity risk management contracts

As at September 30, 2018, Athabasca had the following financial commodity risk management contracts in place:

Instrument	Period	Volume	C$ Average Price/bbl
WTI/WCS fixed price differential swaps	October - December 2018	3,000 bbl/d	$ (17.72)
WTI costless collars	October - December 2018	4,000 bbl/d	$ 69.88 - 85.85

The following table summarizes the Company's net gain (loss) on commodity risk management contracts for the three and nine months ended September 30, 2018 and 2017:

($ Thousands)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Unrealized gain (loss) on commodity risk management contracts	$ 17,302	$ (13,169)	$ 7,468	$ 2,288
Realized gain (loss) on commodity risk management contracts	(8,414)	3,665	(32,938)	6,691
GAIN (LOSS) ON COMMODITY RISK MANAGEMENT CONTRACTS (NET)	$ 8,888	$ (9,504)	$ (25,470)	$ 8,979

The commodity risk management contracts are valued on the 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).

Foreign exchange contracts

As at September 30, 2018, Athabasca had the following foreign exchange risk management contract in place to reduce its exposure to foreign currency risk on its interest payments associated with the 2022 Notes.

Instrument	Period	Amount (US$)	Exchange rate (USD/CAD)
Forward swap contract	February 2019	$ 22,219	$ 1.2505

The following table summarizes the net gain (loss) on foreign exchange risk management contracts for the three and nine months ended September 30, 2018 and 2017:

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
Unrealized gain (loss) on foreign exchange risk management contracts	$ (1,763)	$ —	$ 826	$ —
Realized gain on foreign exchange risk management contracts	1,071	—	1,071	—
GAIN (LOSS) ON FOREIGN EXCHANGE RISK MANAGEMENT CONTRACTS (NET)	$ (692)	$ —	$ 1,897	$ —

The net gains (losses) on foreign exchange risk management contracts are due to fluctuations in the USD/CAD forward exchange rates and the settlement of the August 2018 contract.

Commitments and Contingencies

The following table summarizes Athabasca's estimated future minimum commitments as at September 30, 2018 for the following five years and thereafter:

($ Thousands)	2018	2019	2020	2021	2022	Thereafter	Total
Transportation and processing[1]	$ 23,279	$ 91,924	$ 92,995	$ 114,890	$ 147,427	$ 3,225,892	$ 3,696,407
Repayment of long-term debt[1]	—	—	—	—	581,558	—	581,558
Interest expense on long-term debt[1]	—	57,428	57,428	57,428	28,795	—	201,079
Office leases	728	2,909	2,909	2,909	2,909	6,058	18,422
Purchase commitments and drilling rigs	45,188	1,779	—	—	—	—	46,967
TOTAL COMMITMENTS	$ 69,195	$ 154,040	$ 153,332	$ 175,227	$ 760,689	$ 3,231,950	$ 4,544,433

(1) Commitments which are denominated in US dollars were translated into Canadian dollars at the September 30, 2018 exchange rate of US$1.00 = C$1.2924.

During the third quarter of 2018, Athabasca increased its commitment for dilbit transportation services on the TransCanada Keystone XL pipeline from 10,000 bbl/d to 25,000 bbl/d.

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")

($ Thousands, unless otherwise noted)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
TOTAL GENERAL AND ADMINISTRATIVE	$ 7,550	$ 6,635	$ 22,987	$ 20,129
G&A per boe	$ 2.02	$ 2.00	$ 2.13	$ 2.22

During the three months ended September 30, 2018, Athabasca's G&A expenses increased compared to the same period in the prior year primarily due to higher professional fees and lower capitalized costs offsetting lower salary and benefit costs. In the first nine months of 2018, G&A expenses increased compared to the first nine months of 2017 primarily due to higher professional fees, lower capitalized costs and a full nine months of employee costs related to the Leismer Corner Acquisition. G&A per boe decreased 4% in the first nine months of 2018, compared to the prior year, primarily due to production growth and continued emphasis on cost optimization across the Company.

Gain (loss) on Revaluation of Provisions and Other

($ Thousands)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Contingent payment obligation	$ (8,424)	$ (2,154)	$ (16,236)	$ 14,215
Capital-carry receivable	1,323	2,039	5,176	8,702
Other	13	791	1,763	791
TOTAL GAIN (LOSS) ON REVALUATION OF PROVISIONS AND OTHER	$ (7,088)	$ 676	$ (9,297)	$ 23,708

During the three and nine months ended September 30, 2018, Athabasca incurred losses on revaluation of provisions and other of $7.1 million and $9.3 million, respectively (three and nine months ended September 30, 2017 gains of $0.7 million and $23.7 million, respectively). The respective gains and losses are primarily a result of changes in the estimated value of the Company's contingent payment obligation to Equinor due to fluctuations in forecasted prices for WTI. The contingent payment obligation is remeasured at each reporting period using a call option pricing model with any gains or losses recognized in net income (loss). The call option model includes estimates regarding future WTI prices, foreign exchange rates, inflation rates and Leismer production volumes and is subject to significant measurement uncertainty. The difference in the actual cash outflows ultimately payable with respect to the obligation could be material.

The lower capital-carry accretion income in 2018 was due to the lower capital-carry receivable balances in 2018.

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 $1.9 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.

Current export pipeline capacity constraints significantly impacted Athabasca's financial results in the first nine months of 2018. 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.

Equity Instruments

During the nine months ended September 30, 2018, Athabasca issued 5.8 million common shares in respect of the Company's equity-settled share-based compensation plans.

Outstanding Share Data

As at October 31, 2018	
Common shares issued and outstanding	515,864,362
Stock-based compensation plans:	
Stock options	10,250,333
Restricted share units (2010 RSU Plan)	1,259,293
Restricted share units (2015 RSU Plan)	14,493,733
Performance share units	5,426,600
Deferred share units	2,281,591

For additional information regarding these compensation plans, refer to the consolidated financial statements of the Company for the year ended December 31, 2017.

SUMMARY OF QUARTERLY RESULTS

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

	2018			2017				2016
($ Thousands, unless otherwise noted)	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	69.50	67.90	62.87	55.40	48.21	48.29	51.91	49.29
WTI (C$/bbl)	90.84	87.67	79.53	70.47	60.35	64.95	68.52	65.56
Western Canadian Select (C$/bbl)	61.75	62.89	48.77	54.87	47.76	49.99	49.34	46.61
Edmonton Par (C$/bbl)	81.90	80.60	72.06	69.02	56.62	61.92	63.87	61.59
Edmonton Condensate (C5+) (C$/bbl)	87.01	88.87	79.74	73.74	59.01	65.15	68.73	63.38
AECO (C$/GJ)	1.13	1.12	1.97	1.60	1.38	2.64	2.55	2.93
NYMEX Henry Hub (US$/MMBtu)	2.91	2.80	3.00	2.93	3.00	3.19	3.32	2.98
Foreign exchange (USD : CAD)	1.31	1.29	1.27	1.27	1.25	1.34	1.32	1.33
CONSOLIDATED								
Volumes (boe/d)	40,612	37,658	40,572	42,064	36,133	36,574	26,737	11,630
Realized price (net of cost of diluent) ($/boe)	43.42	39.73	24.23	36.95	34.13	33.68	31.42	34.62
Petroleum and natural gas sales ($)	253,404	251,369	207,979	238,835	187,722	204,098	153,378	57,287
Operating Income ($)(1)	83,703	46,719	16,876	65,002	52,358	43,787	19,204	1,433
Operating Netback ($/boe)(1)	23.21	13.01	4.65	17.25	15.58	13.28	7.99	1.37
Capital expenditures ($)	74,509	54,159	82,261	52,418	73,833	45,674	90,124	66,139
Capital Expenditures Net of Capital-Carry ($)(1)	52,389	38,888	56,661	33,236	67,741	32,181	79,444	66,087
LIGHT OIL DIVISION								
Sales volumes (boe/d)	10,135	11,872	10,495	11,507	7,875	7,246	3,421	3,337
Realized price ($/boe)	46.43	42.68	44.65	40.10	36.83	41.11	45.06	42.20
Petroleum and natural gas sales ($)	43,294	46,107	42,182	42,456	26,680	27,111	13,875	12,955
Operating Income ($)(1)	29,795	30,936	24,292	26,696	13,748	16,391	6,863	6,152
Operating Netback ($/boe)(1)	31.95	28.64	25.72	25.22	18.98	24.85	22.28	20.04
Capital expenditures ($)	60,739	25,557	66,630	40,988	53,406	31,061	77,646	62,003
Capital Expenditures Net of Capital-Carry ($)(1)	38,619	10,286	41,030	21,806	47,314	17,568	66,966	61,951
THERMAL OIL DIVISION								
Bitumen production (bbl/d)	30,477	25,786	30,077	30,557	28,258	29,328	23,316	8,293
Sales volumes (bbl/d)	29,074	27,578	29,857	29,447	28,640	28,970	23,257	8,015
Realized bitumen price ($/bbl)	42.37	38.46	17.05	35.72	33.38	31.82	29.41	31.46
Blended bitumen sales ($)	210,110	205,262	165,797	196,379	161,042	176,987	139,503	44,332
Operating Income (Loss) ($)(1)	62,322	39,635	(6,744)	45,385	34,945	26,661	10,050	(4,719)
Operating Netback ($/bbl)(1)	23.30	15.79	(2.51)	16.75	13.27	10.11	4.80	(6.41)
Capital expenditures ($)	13,767	28,595	15,631	11,368	20,382	14,127	10,868	4,088
OPERATING RESULTS								
Cash Flow from Operating Activities ($)	61,733	27,605	(3,241)	37,060	49,488	28,049	(52,896)	(19,656)
Adjusted Funds Flow ($)(1)	62,151	25,680	(6,360)	41,808	34,400	27,567	(1,649)	(16,867)
Net income (loss) ($)	31,419	(19,267)	(93,330)	(209,588)	5,113	24,233	(29,162)	(779,405)
Net income (loss) per share - basic ($)	0.06	(0.04)	(0.18)	(0.41)	0.01	0.05	(0.06)	(1.92)
BALANCE SHEET ITEMS								
Cash and cash equivalents ($)	128,340	93,293	128,915	163,321	174,076	179,611	212,999	650,301
Restricted cash ($)	114,216	114,212	111,778	113,406	113,372	113,853	113,823	107,012
Capital-carry receivable (discounted) ($)(2)	98,221	119,018	132,745	156,036	169,611	173,714	183,745	191,174
Total assets ($)	2,320,838	2,297,112	2,318,471	2,323,572	2,498,740	2,488,995	2,524,187	2,257,887
Long-term debt ($)(2)	546,505	554,279	541,460	526,206	523,782	541,199	553,377	546,209
Shareholders' equity ($)	1,452,946	1,418,587	1,434,345	1,524,610	1,731,546	1,723,735	1,695,582	1,557,097

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.
(2) 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 nine months ended September 30, 2018, 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 that had a material impact to the consolidated financial statements, except as noted below. Refer to the December 31, 2017 audited consolidated financial statements for the Company for further guidance regarding Athabasca's accounting policies and use of estimates.

Changes in accounting policies

IFRS 15 *Revenue from Contracts with Customers*
The IASB issued IFRS 15 *Revenue from Contracts with Customers* ("IFRS 15") in May 2014. This IFRS replaces IAS 18 *Revenue*, IAS 11 *Construction Contracts* and several revenue-related interpretations. IFRS 15 establishes a single revenue recognition framework which requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser.

Athabasca adopted IFRS 15 on January 1, 2018 using the cumulative effect method. As a result of the adoption of IFRS 15, no cumulative effect adjustment to retained deficit was required and there was no impact on net income (loss) or cash flow.

The additional disclosures required by IFRS 15 are detailed in the unaudited condensed interim consolidated financial statements of the Company for the three and nine months ended September 30, 2018.

IFRS 9 *Financial Instruments*
In July 2014, the IASB issued the final version of IFRS 9 *Financial Instruments* ("IFRS 9") that replaces IAS 39 *Financial Instruments: recognition and measurement* ("IAS 39") and all previous versions of IFRS 9. IFRS 9 brings together all three aspects of the accounting for financial instruments: classification & measurement, impairment and hedge accounting. IFRS 9 introduces a single approach to determining whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. For financial liabilities, IFRS 9 retains most of the requirements of IAS 39; however, where the fair value option is applied to financial liabilities, any change in fair value resulting from an entity's own credit risk is recorded in other comprehensive income. Athabasca adopted IFRS 9 on January 1, 2018. No adjustments were required to the consolidated financial statements on adoption of IFRS 9.

Future Accounting Pronouncements

The following standard that has been issued, but is not yet effective, up to the date of issuance of the Company's consolidated financial statements is disclosed below. The Company intends to adopt this standard when it becomes effective.

IFRS 16 *Leases*
The IASB issued its new Lease Standard on January 13, 2016. This new IFRS requires that, for lessees, former operating leases will now be capitalized and recognized on the balance sheet (exceptions for short-term leases and low-value assets are provided). Lease assets and liabilities will be 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 will adopt the new standard on the required effective date of annual periods beginning on or after January 1, 2019. Two transition methods are available under IFRS 16: full retrospective and cumulative catch-up. A significant amount of transition relief is permitted under the cumulative catch-up method, but will require additional disclosure information. Athabasca currently plans to use the cumulative catch-up method at transition. Athabasca has evaluated its significant contracts and agreements and anticipates the only material impact of the standard will be related to its office lease which upon adoption will be recognized on the balance sheet. The actual impact of applying the standard will depend on the Company's borrowing rate, lease portfolio and the practical expedients applied on January 1, 2019. As new contracts and agreements are entered into and as interpretation of the standard continues, future leases may be identified and recognized on the balance sheet. Athabasca is also currently reviewing the new disclosure requirements for IFRS 16.

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

The following table reconciles cash flow from operating activities in the consolidated financial statements for the three and nine months ended September 30, 2018 and 2017 to Adjusted Funds Flow:

($ Thousands)	Three months ended September 30, 2018	Three months ended September 30, 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017
Cash flow from operating activities	$ 61,733	$ 49,488	$ 86,097	$ 24,637
Acquisition expenses	—	—	—	11,047
Changes in non-cash working capital	(624)	(16,047)	(22,281)	18,598
Settlement of provisions	932	959	5,078	6,033
Long-term deposits	110	—	12,577	—
ADJUSTED FUNDS FLOW	$ 62,151	$ 34,400	$ 81,471	$ 60,315

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 17 - Segmented Information* in the consolidated financial statements for the three and nine months ended September 30, 2018.

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 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 to *Note 17 - Segmented Information* in the consolidated financial statements for the three and nine months ended September 30, 2018.

The Consolidated Operating Income 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 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 to *Note 17 - Segmented Information* in the consolidated financial statements for the three and nine months ended September 30, 2018.

The Consolidated Capital Expenditures Net of Capital-Carry and Light Oil Capital Expenditures Net of Capital-Carry measures in this MD&A are calculated in the tables on pages 6 and 8. These measures allow management and others to evaluate the true net cash outflow related to Athabasca's capital expenditures.

Comparative Figures

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

Internal Controls Update

Athabasca is required to comply with National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109"). NI 52-109 requires that Athabasca disclose in its interim MD&A any material weaknesses in Athabasca's internal control over financial reporting and/or any changes in Athabasca's internal control over financial reporting that occurred during the period that have materially affected, or are reasonably likely to materially affect Athabasca's internal controls over financial reporting. Athabasca confirms that no material weaknesses or such changes were identified in Athabasca's internal controls over financial reporting during the third quarter of 2018.

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;
- the timing of the ramp-up of Hangingstone Project 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 petroleum, natural gas and oil sands 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 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, including the renegotiation of the terms of the North American Free Trade Agreement, the withdrawal of the United States from the Trans-Pacific Partnership and 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 TransCanada 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 2018 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 jurisdiction 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; 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; fluctuations in market prices for crude oil, natural gas, natural gas liquids and bitumen blend; general economic, market and business conditions in Canada, the United States and globally; insurance risks; claims made in respect of Athabasca's operations, properties or assets; the substantial capital requirements of Athabasca's projects and the ability to obtain financing for Athabasca's capital requirements; global financial uncertainty; failure to realize anticipated benefits of acquisitions or divestments; risks related to hydraulic fracturing; factors affecting potential profitability; failure to obtain regulatory approvals or maintain compliance with regulatory requirements; extent of, and cost of compliance with, government laws and regulations and the effect of changes in such laws and regulations from time to time; risks relating to changing royalty regimes; additional funding requirements and liquidity risk; variations in foreign exchange and interest rates; environmental risks and hazards and the cost of compliance with environmental regulations, including the licensee liability rating program, seismic activity regulations, greenhouse gas regulations and potential climate change legislation; risks related to the Murphy Transaction, dependence on Murphy as the operator of the Greater Kaybob assets, dependence on Murphy as the Company's joint venture participant in the Company's Greater Kaybob and Greater Placid assets and dependence on Murphy's continued ability to pay the Greater Kaybob carry commitment, risks associated with events of force majeure; risks related to the Credit Facility, the Letter of Credit Facility, the Unsecured Letter of Credit Facility and the 2022 Notes; geopolitical risks; uncertainties inherent in estimating quantities of reserves and resources; contractual counterparty risks and operational dependence; risks related to future acquisition and joint venture activities; risks and uncertainties inherent in Athabasca's operations, including those related to exploration, development and production of petroleum, natural gas and oil sands reserves and resources, including the production of oil sands reserves and resources using SAGD, TAGD or other in-situ recovery technologies; failure to meet development schedules and potential cost overruns; aboriginal claims; reliance on, competition for, loss of, and failure to attract key personnel; financial assurance covenants and collateral requirements under the Company's pipeline transportation agreements; risks related to gathering and processing facilities and pipeline systems; availability of drilling and related equipment and limitations on access to Athabasca's assets; increases in operating costs could make Athabasca's projects uneconomic; the effect of diluent and natural gas supply constraints and increases in the costs thereof; costs of new technologies; alternatives to and changing demand for petroleum products; gas over bitumen issues affecting operational results; risks related to Athabasca's filings with taxation authorities, including the risk of tax related reviews and reassessments; failure to accurately estimate abandonment and reclamation costs; the potential for management estimates and assumptions to be inaccurate; long-term reliance on third parties; reliance on third party infrastructure; seasonality; risks associated with establishing and maintaining systems of internal controls; competition for, among other things, capital, the acquisition of reserves and resources, export pipeline capacity and skilled personnel; 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; breaches of confidentiality; inaccuracy of forward-looking information; expansion into new activities; 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, 2017 (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, 2017. 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: 64 proved undeveloped or non-producing locations and 35 probable undeveloped locations for a total of 99 undeveloped booked locations with the balance being unbooked locations. The 200 Montney drilling locations referenced on page 6 of this MD&A include: 84 proved undeveloped 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, 2017 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, 2017, 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, Dover West Sands asset in the Development On Hold 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
G&A	general and administrative
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
NYMEX	New York Mercantile Exchange
OPEC	Organization of the Petroleum Exporting Countries
SAGD	steam assisted gravity drainage
SOR	steam to oil ratio
TAGD	thermal assisted gravity drainage
US$	United States Dollars
WTI	West Texas Intermediate
WCS	Western Canadian Select