Management's Discussion and Analysis

Q1 2019

ATHABASCA OIL CORPORATION

This Management's Discussion and Analysis of the financial condition and results of operations ("MD&A") of Athabasca Oil Corporation ("Athabasca" or the "Company") is dated May 8, 2019 and should be read in conjunction with the audited consolidated financial statements of the Company for the years ended December 31, 2018 and 2017. These financial statements, including the comparative figures, were prepared in accordance with International Financial Reporting Standards ("IFRS"). This MD&A contains forward looking information based on the Company's current expectations and projections. For information on the material factors and assumptions underlying such forward-looking information, refer to the "Advisories and Other Guidance" section within this MD&A. Also see the "Advisories and Other Guidance" section within this MD&A for important information regarding the Company's reserves and resource information and abbreviations included in this MD&A. Additional information relating to Athabasca is available on SEDAR at www.sedar.com, including the Company's most recent Annual Information Form dated March 6, 2019 ("AIF"). The Company's common shares are listed on the Toronto Stock Exchange under the trading symbol "ATH".

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ATHABASCA'S STRATEGY

Athabasca is a liquids-weighted intermediate producer with exposure to Canada's most active resource plays (Montney, Duvernay, Oil Sands). The Company offers investors excellent exposure to 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 Returns
- Thermal Oil: Low Decline Production
- Financial Sustainability: Flexible Capital, Strong Liquidity

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

HIGHLIGHTS FOR THE QUARTER ENDED MARCH 31, 2019

Corporate

- Production of 39,206 boe/d with an 86% liquids weighting.
- Consolidated Operating Income[(1)] of $58.6 million, Operating Netback[(1)] of $16.77/boe and Adjusted Funds Flow[(1)] of $41.6 million, driven by strong operational performance and a significantly improved Canadian pricing environment.
- Net income of $206.8 million.
- Consolidated Free Cash Flow[(1)] of $9.9 million with positive contributions from both Light Oil and Thermal Oil.
- Successfully closed the sale of the Company's Leismer infrastructure assets for $265 million of cash proceeds.
- Strong balance sheet position with funding capacity of $459.3 million including $272.2 million of cash and cash equivalents, $126.6 million of available credit and letter of credit facilities and a $60.5 million (undiscounted) capital-carry balance.

Light Oil Division

- Production of 11,712 boe/d, representing growth of 12% over the first quarter of 2018.
- Operating Netback[(1)] of $29.67/boe driven by a high liquids weighting of 54% and low lifting costs.
- Record Operating Income[(1)] of $31.3 million, an increase of 29% over the first quarter of 2018.
- Capital Expenditures Net of Capital-Carry[(1)] of $8.6 million with six (gross) wells drilled, eight (gross) wells completed and four (gross) wells being placed on production in Greater Kaybob.
- Light Oil Free Cash Flow[(1)] of $22.6 million.

Thermal Oil Division

- Production of 27,494 bbl/d, in-line with Government mandated curtailments.
- Operating Netback[(1)] of $18.50/bbl driven by strong realized pricing for bitumen of $42.56/bbl.
- Operating Income[(1)] of $45.1 million ($36.0 million at Leismer and $9.1 million at Hangingstone).
- Capital expenditures of $23.1 million, including drilling five well pairs and four observation wells at Leismer.
- Thermal Oil Free Cash Flow[(1)] of $22.0 million.

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

FINANCIAL & OPERATIONAL HIGHLIGHTS

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

($ Thousands, unless otherwise noted)	Three months ended March 31, 2019	2018
CONSOLIDATED		
Petroleum and natural gas production (boe/d)	39,206	40,572
Operating Income[(1)(2)]	$ 58,602	$ 16,876
Operating Netback[(1)(2)] ($/boe)	$ 16.77	$ 4.65
Capital expenditures	$ 52,964	$ 82,261
Capital Expenditures Net of Capital-Carry[(1)]	$ 31,756	$ 56,661
LIGHT OIL DIVISION		
Petroleum and natural gas production (boe/d)	11,712	10,495
Percentage liquids (%)	54%	50%
Operating Income[(1)]	$ 31,280	$ 24,292
Operating Netback[(1)] ($/boe)	$ 29.67	$ 25.72
Capital expenditures	$ 29,855	$ 66,630
Capital Expenditures Net of Capital-Carry[(1)]	$ 8,647	$ 41,030
THERMAL OIL DIVISION		
Bitumen production (bbl/d)	27,494	30,077
Operating Income (Loss)[(1)]	$ 45,128	$ (6,744)
Operating Netback[(1)] ($/bbl)	$ 18.50	$ (2.51)
Capital expenditures	$ 23,109	$ 15,631
CASH FLOW AND FUNDS FLOW		
Cash flow from operating activities	$ (18,572)	$ (3,241)
per share - basic	$ (0.04)	$ (0.01)
Adjusted Funds Flow[(1)]	$ 41,619	$ (6,360)
per share - basic	$ 0.08	$ (0.01)
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)		
Net income (loss) and comprehensive income (loss)	$ 206,796	$ (93,330)
per share - basic	$ 0.40	$ (0.18)
per share - diluted	$ 0.39	$ (0.18)
COMMON SHARES OUTSTANDING		
Weighted average shares outstanding - basic	516,011,483	510,191,864
Weighted average shares outstanding - diluted	524,731,043	510,191,864

As at ($ Thousands)	March 31, 2019	December 31, 2018
LIQUIDITY AND BALANCE SHEET		
Cash and cash equivalents	$ 272,240	$ 73,898
Available credit facilities[(3)]	$ 126,604	$ 126,491
Capital-carry receivable (current and long-term portion - undiscounted)	$ 60,467	$ 81,675
Face value of long-term debt[(4)]	$ 601,200	$ 614,070

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.
(2) Includes realized commodity risk management loss of $17.8 million for the three months ended March 31, 2019 ($0.7 million for the three months ended March 31, 2018).
(3) Includes available credit under Athabasca's Credit Facility and Unsecured Letter of Credit Facility (see page 14).
(4) The face value of the 2022 Notes is US$450 million. The 2022 Notes were translated into Canadian dollars at the March 31, 2019 exchange rate of US$1.00 = C$1.3360.

BUSINESS ENVIRONMENT

In December, the Alberta Government announced mandatory industry production curtailments starting in January 2019 to alleviate the high differential situation until additional egress is added. Following the announcement, the Western Canadian Select (“WCS”) heavy oil pricing outlook has significantly improved. WCS prices averaged $56.62 in the first quarter of 2019, a 123% increase from $25.36 in the fourth quarter of 2018. Athabasca remains supportive of these actions and views them as a necessary step to normalize pricing and provide a bridge to permanent market access initiatives.

Industry and government crude by rail remain an important factor in managing differentials and Alberta inventories. Rail capacity continues to increase and base line utilization is expected to build through 2019 as long term contracts are operationalized.

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

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 March 31,		
(Average)	2019	2018	Change
Crude oil:			
West Texas Intermediate (WTI) (US$/bbl)(1)	$ 54.90	$ 62.87	(13)%
West Texas Intermediate (WTI) (C$/bbl)(1)	$ 72.97	$ 79.53	(8)%
Western Canadian Select (WCS) (C$/bbl)(2)	$ 56.62	$ 48.77	16 %
Edmonton Par (C$/bbl)(3)	$ 66.41	$ 72.06	(8)%
Edmonton Condensate (C5+) (C$/bbl)(4)	$ 66.60	$ 79.74	(16)%
WCS Differential:			
WTI vs. WCS (US$/bbl)	$ (12.29)	$ (24.32)	49 %
WTI vs. WCS (C$/bbl)	$ (16.35)	$ (30.76)	47 %
Edmonton Par Differential:			
WTI vs. Edmonton Par (US$/bbl)	$ (4.85)	$ (5.91)	18 %
WTI vs. Edmonton Par (C$/bbl)	$ (6.56)	$ (7.47)	12 %
Natural gas:			
AECO (C$/GJ)(5)(6)	$ 2.49	$ 1.97	26 %
NYMEX Henry Hub (US$/MMBtu)(6)	$ 3.15	$ 3.00	5 %
Foreign exchange:			
USD : CAD	1.33	1.27	5 %

Primary benchmark for:

(1) Crude oil pricing in North America.
(2) Athabasca's blended bitumen sales.
(3) Crude oil sales in the Company's Light Oil Division.
(4) Condensate sales in the Company's Light Oil Division and for diluent purchases in the Thermal Oil Division.
(5) Natural gas consumed by Athabasca in order to generate steam in the Thermal Oil Division.
(6) Natural gas sales in the Company's Light Oil Division.

OUTLOOK

2019 Operational & Financial Guidance ($ millions, unless otherwise noted)	Full year
Corporate (net)	
Production (boe/d)	37,500 - 40,000
Capital Expenditures Net of Capital-Carry(1)(2)	$95 - $110
Light Oil (net)	
Production (boe/d)	10,000 - 11,000
Capital Expenditures Net of Capital-Carry(1)(2)	$15 - $30
Thermal Oil (net)	
Production (bbl/d)	27,500 - 29,000
Capital expenditures(1)	$80
Adjusted Funds Flow Sensitivity(3)	
US$60 WTI / US$17.50 WCS diff	$165
US$65 WTI / US $17.50 WCS diff	$205

(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.
(3) Sensitivity incorporates actual Q1 2019 results, current hedge positions, and flat pricing assumptions for Q2-Q4 2019 (US$10 MSW diffs, US$5 C5 diffs, C$1.50 AECO, 0.75 C$/US$ FX).

Athabasca's guidance for 2019 capital expenditures remains unchanged with activity levels designed to maintain base production and a strong balance sheet.

The Company is maintaining its $95 - $110 million capital program with production guidance between 37,500 - 40,000 boe/d. Forecasted Adjusted Funds Flow for 2019 is estimated at $205 million (US$65 WTI & US$17.50 WCS differential for the balance of 2019) with resulting Consolidated Free Cash Flow of approximately $100 million.

Delivering consistent free cash flow will afford Athabasca flexibility to direct free cash flow to debt reduction, share buy backs or future capital projects.

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 March 31, 2019	Three months ended March 31, 2018
PRODUCTION		
Oil and condensate (bbl/d)	5,191	4,196
Natural gas (Mcf/d)	32,576	31,511
Natural gas liquids (bbl/d)	1,092	1,047
Bitumen (bbl/d)	27,494	30,077
Total (boe/d)	39,206	40,572

($ Thousands, unless otherwise noted)	Three months ended March 31, 2019	Three months ended March 31, 2018
Petroleum and natural gas sales	$ 226,127	$ 207,979
Royalties	(3,905)	(3,104)
Cost of diluent	(78,543)	(119,988)
Operating expenses	(43,559)	(44,677)
Transportation and marketing	(23,712)	(22,662)
	$ 76,408	$ 17,548
Realized loss on commodity risk management contracts	(17,806)	(672)
Consolidated Operating Income[1]	$ 58,602	$ 16,876
REALIZED PRICES		
Oil and condensate ($/bbl)	$ 64.15	$ 72.68
Natural gas ($/Mcf)	3.40	3.47
Natural gas liquids ($/bbl)	39.20	51.99
Blended bitumen sales ($/bbl)	51.95	42.15
Realized price (net of cost of diluent) ($/boe)	42.25	24.23
Royalties ($/boe)	(1.12)	(0.85)
Operating expenses ($/boe)	(12.47)	(12.30)
Transportation and marketing ($/boe)	(6.79)	(6.24)
	$ 21.87	$ 4.84
Realized loss on commodity risk management contracts ($/boe)	(5.10)	(0.19)
CONSOLIDATED OPERATING NETBACK[1] ($/boe)	$ 16.77	$ 4.65

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

Consolidated Segments Income (Loss)

($ Thousands)	Three months ended March 31, 2019	Three months ended March 31, 2018
Consolidated Operating Income[1]	$ 58,602	$ 16,876
Unrealized loss on commodity risk management contracts	(23,985)	(3,492)
Depletion and depreciation	(34,475)	(38,448)
Gain on sale of assets	221,606	—
Exploration expenses	(626)	(306)
CONSOLIDATED SEGMENTS INCOME (LOSS)	$ 221,122	$ (25,370)

(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 March 31, 2019	Three months ended March 31, 2018
Light Oil Division	$ 29,855	$ 66,630
Thermal Oil Division	23,109	15,631
TOTAL CAPITAL EXPENDITURES[1]	$ 52,964	$ 82,261
Less: Greater Kaybob capital-carry	(21,208)	(25,600)
TOTAL CAPITAL EXPENDITURES NET OF CAPITAL-CARRY[2]	$ 31,756	$ 56,661

(1) For the three months ended March 31, 2019, capital expenditures include $2.2 million of capitalized staff costs (March 31, 2018 - $3.1 million).
(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

LIGHT OIL DIVISION

Overview

Athabasca produces light oil and liquids-rich natural gas from unconventional reservoirs. Development has been focused on the Montney in the Greater Placid area and the Duvernay in the Greater Kaybob area near the town of Fox Creek, Alberta. As at December 31, 2018, the Light Oil Division had approximately 74 MMboe of Proved plus Probable Reserves[1]. Athabasca's Light Oil Division assets are supported by 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.

In Greater Placid, Athabasca has a 70% operated working interest in approximately 80,000 gross Montney acres. Over the past two years, Athabasca has transitioned Greater Placid from early stage resource capture to efficient multi-well pad development. An inventory of over 200[1] high-graded gross drilling locations positions the Company for multi-year growth in this area.

In Greater Kaybob, Athabasca has a 30% non-operated interest in over 200,000 gross acres of commercially prospective Duvernay lands with exposure to both liquids-rich gas and volatile oil opportunities and an inventory of approximately 1,000[2] gross drilling locations. Seventy-five percent of Athabasca’s Greater Kaybob development capital is currently funded by its joint venture partner under a multi-year $219 million (undiscounted) capital-carry commitment which was designed to support approximately $1 billion of gross Duvernay investment. The capital-carry balance remaining at March 31, 2019 was $60.5 million (undiscounted).

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

Light Oil Operating Results

	Three months ended March 31, 2019	2018
PRODUCTION		
Oil and condensate (bbl/d)	5,191	4,196
Natural gas (Mcf/d)	32,576	31,511
Natural gas liquids (bbl/d)	1,092	1,047
Total (boe/d)	11,712	10,495
Consisting of:		
Greater Placid area (boe/d)	7,004	8,213
% liquids	47%	46%
Greater Kaybob area (boe/d)	4,708	2,282
% liquids	64%	65%

($ Thousands, unless otherwise noted)	Three months ended March 31, 2019	2018
Petroleum and natural gas sales	$ 43,778	$ 42,182
Royalties	(1,895)	(1,912)
Operating expenses	(5,811)	(8,326)
Transportation and marketing	(4,792)	(7,652)
Light Oil Operating Income(1)	$ 31,280	$ 24,292
REALIZED PRICES		
Oil and condensate ($/bbl)	$ 64.15	$ 72.68
Natural gas ($/Mcf)	3.40	3.47
Natural gas liquids ($/bbl)	39.20	51.99
Realized price ($/boe)	41.53	44.65
Royalties ($/boe)	(1.80)	(2.02)
Operating expenses ($/boe)	(5.51)	(8.81)
Transportation and marketing ($/boe)	(4.55)	(8.10)
LIGHT OIL OPERATING NETBACK(1) ($/boe)	$ 29.67	$ 25.72

(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 11,712 boe/d during the first quarter of 2019, an increase of 12% compared to the first quarter of 2018. Production growth was primarily the result of additional development in the Duvernay at Greater Kaybob with 9 (gross) wells brought on production in the fourth quarter of 2018 and first quarter of 2019. Greater Placid volumes have decreased relative to the prior year, as the Company deferred completions activity on a previously drilled multi-well pad (7 gross wells) in the fourth quarter of 2018 in response to the low commodity price environment.

Athabasca’s Light Oil Operating Netback was $29.67/boe in the first quarter of 2019, a 15% increase from the prior year first quarter. The increase was primarily due to lower operating costs, and lower transportation and marketing expenses, partially offset by lower benchmark prices for oil and liquids. Operating expenses per boe in the first quarter of 2019 have decreased relative to the prior year period as a result of higher production, lower water disposal and processing fees, and approximately $1.8 million of prior period adjustments. Transportation and marketing fees per boe in the first quarter of 2019 have decreased relative to the prior year period as a result of lower average contract pricing for transportation of the Company’s natural gas.

As a result of higher production and a higher netback, Athabasca generated record Light Oil Operating Income of $31.3 million in the first quarter of 2019, a 29% increase over the comparable 2018 period.

Light Oil Segment Income

($ Thousands)	Three months ended March 31, 2019	2018
Light Oil Operating Income[1]	$ 31,280	$ 24,292
Depletion and depreciation	(19,916)	(16,700)
Loss on sale of assets	(1,205)	—
Exploration expenses	—	(2)
LIGHT OIL SEGMENT INCOME	$ 10,159	$ 7,590

(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 $3.2 million in the first quarter of 2019, compared to the same period in the prior year, primarily due to higher production volumes.

Light Oil Capital Expenditures

($ Thousands)	Three months ended March 31, 2019	2018
Greater Placid		
Drilling, completion and equipping	$ 107	$ 29,763
Facilities	49	1,133
Other	1,245	2,055
	1,401	32,951
Greater Kaybob		
Drilling, completion and equipping	24,833	29,461
Facilities	3,068	4,395
Other	553	(177)
	28,454	33,679
TOTAL LIGHT OIL CAPITAL EXPENDITURES[1]	$ 29,855	$ 66,630
Less: Greater Kaybob capital-carry	(21,208)	(25,600)
TOTAL CAPITAL EXPENDITURES NET OF CAPITAL-CARRY[2]	$ 8,647	$ 41,030

(1) For the three months ended March 31, 2019, capital expenditures include $1.0 million of capitalized staff cost (March 31, 2018 - $1.4 million).
(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

Including recovery of the capital-carry, Athabasca's net cash outflow from capital expenditures in Greater Kaybob was $7.2 million for the three months ended March 31, 2019 (March 31, 2018 - $8.1 million).

During the three months ended March 31, 2019, Light Oil capital expenditures of $29.9 million were primarily spent at Greater Kaybob where operations included two drilling rigs and a single frac crew. The following table summarizes Athabasca's well activity for the three months ended March 31, 2019 and 2018:

	Three months ended March 31, 2019		2018	
Well activity[1]	Gross	Net	Gross	Net
Greater Placid				
Wells drilled	—	—	4	2.8
Wells completed	—	—	5	3.5
Wells brought on production	—	—	5	3.5
Greater Kaybob				
Wells drilled	6	1.8	13	3.9
Wells completed	8	2.4	5	1.5
Wells brought on production	4	1.2	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.

THERMAL OIL DIVISION

Overview

Athabasca's Thermal Oil Division consists of two producing oil sands projects and a large resource base of expansion and exploration areas in the Athabasca region of northeastern Alberta. The Thermal Oil Division underpins Athabasca's low corporate production decline, supporting significant free cash flow potential with low sustaining capital requirements.

Athabasca has a 100% working interest in the producing Leismer Thermal Oil Project (the "Leismer Project") and the delineated Corner lease. The Leismer Project was commissioned in 2010 and has proven reserves in place to support a flat production profile for over 40 years and a reserve life index of approximately 90 years (proved plus probable). The Leismer Project has Proved plus Probable Reserves of approximately 675 MMbbl(1) and 0.3 billion barrels (risked)(1) (0.3 billion barrels unrisked)(1) of Best Estimate Development Pending Contingent Resources. The Corner lease has Proved plus Probable Reserves of approximately 353 MMbbl(1) and 0.4 billion barrels (risked)(1) (0.5 billion barrels unrisked)(1) of Best Estimate Development Pending Contingent Resources. The Leismer Project and Corner assets have received regulatory approval for future development phases of up to a combined 80,000 bbl/d.

Athabasca also has a 100% working interest in the producing Hangingstone Thermal Oil Project (the "Hangingstone Project"). The Hangingstone Project was commissioned in July 2015 and has proven reserves in place to support a flat production profile for over 40 years and a reserve life index of approximately 50 years (proved plus probable). Hangingstone has Proved plus Probable Reserves of approximately 177 MMbbl(1). Minimal development and maintenance capital will be required in the near-term to maintain Hangingstone production.

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

Athabasca's Thermal Oil Division has access to multiple sales points with marketing agreements on the Enbridge Waupisoo transportation pipeline. Athabasca has also 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.

Leismer Infrastructure Transaction

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

During the three months ended March 31, 2019, Athabasca received $265.0 million of cash consideration from Enbridge and incurred $2.8 million of transaction costs, resulting in net proceeds of $262.2 million. Athabasca de-recognized $39.9 million of PP&E and $0.4 million in decommissioning obligations resulting in a gain of $222.8 million on the Leismer Infrastructure Transaction.

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

Leismer Operating Results

	Three months ended March 31, 2019	2018
VOLUMES		
Bitumen production (bbl/d)	18,438	21,021
Bitumen sales (bbl/d)	18,213	21,049
Blended bitumen sales (bbl/d)	25,817	30,669

($ Thousands, unless otherwise noted)	Three months ended March 31, 2019	2018
Blended bitumen sales	$ 119,316	$ 115,441
Cost of diluent	(50,178)	(84,137)
Total bitumen sales	69,138	31,304
Royalties	(1,374)	(857)
Operating expenses - non-energy	(12,834)	(13,817)
Operating expenses - energy	(9,407)	(6,498)
Transportation and marketing	(9,511)	(5,280)
Leismer Operating Income(1)	$ 36,012	$ 4,852
REALIZED PRICE		
Blended bitumen sales ($/bbl)	$ 51.35	$ 41.82
Bitumen sales ($/bbl)	$ 42.18	$ 16.52
Royalties ($/bbl)	(0.84)	(0.45)
Operating expenses - non-energy ($/bbl)	(7.83)	(7.29)
Operating expenses - energy ($/bbl)	(5.74)	(3.43)
Transportation and marketing ($/bbl)	(5.80)	(2.79)
LEISMER OPERATING NETBACK(1) ($/bbl)	$ 21.97	$ 2.56

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

Leismer production in the first quarter of 2019 was 12% lower than the first quarter of 2018 as the Company recovered from voluntary production curtailments in late 2018 as a response to the unprecedented WCS differential environment. Athabasca is taking deliberate steps to prudently manage long term reservoir performance and maximize profitability, including steam optimization ahead of the start-up of the L7 sustaining pad. First quarter production was in-line with Government mandated curtailments.

The Leismer Operating Netback was $21.97/bbl during the first quarter of 2019, compared to $2.56/bbl in the comparable 2018 period. The increase in 2019 was primarily a result of higher realized bitumen sales prices due to a significant reduction in WCS differentials resulting in a 16% increase in the WCS benchmark price, lower product quality differentials and lower costs for diluent compared to the first quarter of 2018.

Total operating expenses were $13.57/bbl in the first quarter of 2019, an increase of 27% from the first quarter of 2018. The non-energy costs increased on a per bbl basis in the first quarter of 2019 primarily due to lower production volumes. Energy operating costs were higher as the Company maintained normal steam levels throughout curtailments and associated recovery in order to optimize reservoir pressure, as well as due to higher power and gas prices.

In the first quarter of 2019, as part the Leismer Infrastructure Transaction, Athabasca entered into a multi-year contract for priority service on the Leismer pipelines and access to the Cheecham diluent tanks for an annual cost of approximately $26 million. First quarter transportation and dilution expenses include costs incurred under this new contract from January 15 through March 31, 2019.

Leismer Operating Income was $36.0 million in the first quarter of 2019 compared to $4.9 million in the first quarter of 2018 with a significantly higher netback offsetting lower production volumes.

Seasonality has an impact on the Thermal Oil business. In the first and fourth quarters of a given year, dilution costs will generally increase as more diluent is required to meet pipeline specifications.

Hangingstone Operating Results

	Three months ended March 31,	
	2019	2018
VOLUMES		
Bitumen production (bbl/d)	9,056	9,056
Bitumen sales (bbl/d)	8,887	8,808
Blended bitumen sales (bbl/d)	13,182	13,035

	Three months ended March 31,	
($ Thousands, unless otherwise noted)	2019	2018
Blended bitumen sales	$ 63,033	$ 50,356
Cost of diluent	(28,365)	(35,851)
Total bitumen sales	34,668	14,505
Royalties	(636)	(335)
Operating expenses - non-energy	(8,887)	(11,190)
Operating expenses - energy	(6,620)	(4,846)
Transportation and marketing	(9,409)	(9,730)
Hangingstone Operating Income (Loss)(1)	$ 9,116	$ (11,596)
REALIZED PRICE		
Blended bitumen sales ($/bbl)	$ 53.13	$ 42.92
Bitumen sales ($/bbl)	$ 43.34	$ 18.30
Royalties ($/bbl)	(0.80)	(0.42)
Operating expenses - non-energy ($/bbl)	(11.11)	(14.12)
Operating expenses - energy ($/bbl)	(8.28)	(6.11)
Transportation and marketing ($/bbl)	(11.76)	(12.27)
HANGINGSTONE OPERATING NETBACK(1) ($/bbl)	$ 11.39	$ (14.62)

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

Hangingstone production was flat in the first quarter of 2019 compared to the first quarter of 2018. Despite continued steam chamber development over the past year, production was impacted as the Company recovered from voluntary production curtailments in late 2018 as a response to the unprecedented WCS differential environment. First quarter production was in-line with Government mandated curtailments.

The Hangingstone Operating Netback was $11.39/bbl in the first quarter of 2019 compared to $(14.62)/bbl during the same period in 2018. The increase in 2019 was primarily a result of higher realized bitumen sales prices due to a significant reduction in WCS differentials, lower product quality differentials and lower costs for diluent compared to the first quarter of 2018.

Total operating expenses were $19.39/bbl in the first quarter of 2019 compared to $20.23/bbl during the same period in 2018. The decreased non-energy operating expenses in the first quarter of 2019 were due to the continued optimization of field operations over the past year. Energy operating costs were higher as the Company maintained normal steam levels throughout curtailments and associated recovery in order to optimize reservoir pressure, as well as due to higher power and gas prices.

Hangingstone Operating Income was $9.1 million in the first quarter of 2019 compared to an Operating Loss of $11.6 million in the first quarter of 2018 primarily as a result of higher realized sales prices and lower diluent costs.

Seasonality has an impact on the Thermal Oil business. In the first and fourth quarters of a given year, dilution costs will generally increase as more diluent is required to meet pipeline specifications.

Consolidated Thermal Oil Operating Results

	Three months ended March 31,	
	2019	2018
VOLUMES		
Bitumen production (bbl/d)	27,494	30,077
Bitumen sales (bbl/d)	27,100	29,857
Blended bitumen sales (bbl/d)	38,999	43,704

	Three months ended March 31,	
($ Thousands, unless otherwise noted)	**2019**	**2018**
Blended bitumen sales	$ 182,349	$ 165,797
Cost of diluent	(78,543)	(119,988)
Total bitumen sales	103,806	45,809
Royalties	(2,010)	(1,192)
Operating expenses - non-energy	(21,721)	(25,007)
Operating expenses - energy	(16,027)	(11,344)
Transportation and marketing	(18,920)	(15,010)
Thermal Oil Operating Income (Loss)[1]	$ 45,128	$ (6,744)
REALIZED PRICE		
Blended bitumen sales ($/bbl)	$ 51.95	$ 42.15
Bitumen sales ($/bbl)	$ 42.56	$ 17.05
Royalties ($/bbl)	(0.82)	(0.44)
Operating expenses - non-energy ($/bbl)	(8.91)	(9.31)
Operating expenses - energy ($/bbl)	(6.57)	(4.22)
Transportation and marketing ($/bbl)	(7.76)	(5.59)
THERMAL OIL OPERATING NETBACK[1] ($/bbl)	$ 18.50	$ (2.51)

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

Thermal Oil Segment Income (Loss)

	Three months ended March 31,	
($ Thousands)	**2019**	**2018**
Thermal Oil Operating Income (Loss)[1]	$ 45,128	$ (6,744)
Depletion and depreciation	(14,559)	(21,748)
Gain on sale of assets	222,811	—
Exploration expenses	(626)	(304)
THERMAL OIL SEGMENT INCOME (LOSS)	$ 252,754	$ (28,796)

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

During the three months ended March 31, 2019, Athabasca recorded a gain of $222.8 million on the Leismer Infrastructure Transaction.

Depletion and depreciation expense decreased $7.2 million in the first quarter of 2019 compared to the same period in the prior year primarily due to lower production volumes and a decrease in the Hangingstone depletion rate.

Thermal Oil Capital Expenditures

($ Thousands)	Three months ended March 31, 2019	2018
Leismer Project	$ 21,977	$ 11,144
Hangingstone Project	1,059	3,668
Other Thermal Oil exploration	73	819
TOTAL THERMAL OIL CAPITAL EXPENDITURES(1)	$ 23,109	$ 15,631

(1) For the three months ended March 31, 2019, capital expenditures include $1.2 million of capitalized staff costs (March 31, 2018 - $1.7 million).

Thermal Oil capital expenditures for the first quarter of 2019 of $23.1 million were primarily associated with the drilling of five well pairs and four observation wells on Pad 7 at Leismer. The average producer lateral length of the Pad 7 wells is 1,250 meters, a 50% increase over existing horizontal wells at Leismer, and all well pairs were successfully drilled into high quality reservoir. The Company expects initial steaming to commence this summer with production anticipated in the fourth quarter of 2019.

CORPORATE REVIEW

Liquidity and Capital Resources

Funding

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

As at March 31, 2019, Athabasca had $272.2 million of unrestricted cash and cash equivalents, a fully undrawn $120.0 million Credit Facility (defined below), $6.6 million of available credit under its Unsecured Letter of Credit Facility (defined below), and an additional $60.5 million (undiscounted) of funding available through the capital-carry receivable.

In 2019, 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 2019, depending on the Company's level of capital spend and the commodity price environment, the Company may require additional funding which could include debt, equity, joint ventures, asset sales or other external financing. The availability of any additional future funding will depend on, among other things, the current commodity price environment, operating performance, the Company's credit rating and the current availability of the equity and debt capital markets.

Indebtedness

As at ($ Thousands)	March 31, 2019	December 31, 2018
2022 Notes(1)	$ 601,200	$ 614,070
Debt issuance costs	(47,081)	(47,081)
Amortization of debt issuance costs	16,292	14,151
TOTAL LONG-TERM DEBT	$ 570,411	$ 581,140

(1) As at March 31, 2019, the US dollar denominated 2022 Notes were translated into Canadian dollars at the period end exchange rate of US$1.00 = C$1.3360.

Athabasca had the following notes and credit facilities in place as at March 31, 2019:

2022 Notes

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

- February 24, 2019 to February 23, 2020 - 104.9% of principal
- February 24, 2020 to February 23, 2021 - 102.5% of principal
- February 24, 2021 to maturity - 100% of principal

Credit Facility

In the fourth 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.

As at March 31, 2019, amounts borrowed under the Credit Facility bear interest at a floating rate based on the applicable Canadian prime rate, US base rate, LIBOR or bankers' acceptance rate, plus a margin of 2.00% to 3.00%. The Company incurs an issuance fee for letters of credit of 3.00% and a standby fee on the undrawn portion of the Credit Facility of 0.675%. As at March 31, 2019, the Company had no amounts drawn or letters of credit issued and outstanding under the Credit Facility.

Cash-Collateralized Letter of Credit Facility

Athabasca maintains a $110.0 million cash-collateralized letter of credit facility (the "Letter of Credit Facility") with a Canadian bank for issuing letters of credit to counterparties. The facility is available on a demand basis and letters of credit issued under the Letter of Credit Facility incur an issuance fee of 0.25%. Under the terms of the Letter of Credit Facility, Athabasca is required to contribute cash to a cash-collateral account equivalent to 101% of the value of all letters of credit issued under the facility. As at March 31, 2019, Athabasca had $105.3 million (December 31, 2018 - $110.0 million) in letters of credit issued and outstanding under the Letter of Credit Facility.

Unsecured Letter of Credit Facility

In the fourth quarter of 2018, Athabasca entered into a $25.0 million unsecured letter of credit facility (the "Unsecured Letter of Credit Facility") with a Canadian bank which is supported by a performance security guarantee from Export Development Canada. The facility is available on a demand basis and letters of credit issued under this facility incur an issuance and performance guarantee fee of 2.20%. As at March 31, 2019, the Company had $18.4 million of letters of credit issued and outstanding under the Unsecured Letter of Credit Facility.

Financing and Interest

	Three months ended March 31,	
($ Thousands)	**2019**	**2018**
Financing and interest expense on indebtedness	$ 15,195	$ 14,697
Amortization of debt issuance costs	2,240	2,026
Accretion of provisions	2,846	2,857
Interest expense on lease liability	453	—
TOTAL FINANCING AND INTEREST	$ 20,734	$ 19,580

During the three months ended March 31, 2019 and 2018, financing and interest expenses were primarily attributable to the Company's 2022 Notes. The interest expense on the lease liability relates to the adoption IFRS 16 *Leases* on January 1, 2019 which resulted in a new implied interest expense of $0.5 million.

Foreign Exchange Gain (Loss), Net

	Three months ended March 31,	
($ Thousands)	**2019**	**2018**
Unrealized foreign exchange gain (loss)	$ 12,870	$ (15,193)
Realized foreign exchange gain (loss)	740	(219)
FOREIGN EXCHANGE GAIN (LOSS), NET	$ 13,610	$ (15,412)

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

Risk Management Contracts

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

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

Athabasca is also exposed to foreign exchange risk on the principal and interest components of its US dollar denominated 2022 Notes and has entered into a US dollar forward swap contract to reduce its exposure to foreign currency risk related to its August 2019 interest payment.

Financial commodity risk management contracts

As at March 31, 2019, the following financial commodity risk management contracts were in place:

Instrument	Period	Volume		C$ Average Price/bbl		Implied US$ Average Price/bbl(1)
WTI fixed price swaps	April - June 2019	2,000 bbl/d	$	80.00	$	59.88
WTI/WCS fixed price differential swaps	April - June 2019	18,000 bbl/d	$	(27.01)	$	(20.22)
WTI fixed price swaps	July - September 2019	10,000 bbl/d	$	79.95	$	59.84
WTI/WCS fixed price differential swaps	July - September 2019	15,000 bbl/d	$	(28.35)	$	(21.22)
WTI fixed price swaps	October - December 2019	10,000 bbl/d	$	79.95	$	59.84
WTI/WCS fixed price differential swaps	October - December 2019	13,000 bbl/d	$	(28.46)	$	(21.30)

(1) The implied US$ Average Price/bbl was calculated using the March 31, 2019 exchange rate of US$1.00 = C$1.3360.

Additional financial commodity risk management activity related to 2019 has taken place subsequent to March 31, 2019, as noted in the table below:

Instrument	Period	Volume		C$ Average Price/bbl		Implied US$ Average Price/bbl(1)
WTI fixed price swaps	May - June 2019	10,000 bbl/d	$	86.35	$	64.64
WTI costless collars	May - June 2019	2,000 bbl/d	$	80.00 - 86.10	$	59.88 - 64.45
WTI fixed price swaps	July - September 2019	2,000 bbl/d	$	83.83	$	62.75
WTI costless collars	July - September 2019	2,000 bbl/d	$	80.00 - 86.10	$	59.88 - 64.45
WTI fixed price swaps	October - December 2019	2,000 bbl/d	$	83.83	$	62.75
WTI costless collars	October - December 2019	2,000 bbl/d	$	80.00 - 86.10	$	59.88 - 64.45

(1) The implied US$ Average Price/bbl was calculated using the March 31, 2019 exchange rate of US$1.00 = C$1.3360.

The following table summarizes the Company's net loss on commodity risk management contracts for the three months ended March 31, 2019 and 2018:

($ Thousands)	Three months ended March 31, 2019	Three months ended March 31, 2018
Unrealized loss on commodity risk management contracts	$ (23,985)	$ (3,492)
Realized loss on commodity risk management contracts	(17,806)	(672)
LOSS ON COMMODITY RISK MANAGEMENT CONTRACTS, NET	$ (41,791)	$ (4,164)

The following table summarizes the sensitivity in the pricing for Athabasca's commodity risk management contracts:

As at March 31, 2019	Change in WTI		Change in WCS differential	
	Increase of US$5.00/bbl	Decrease of US$5.00/bbl	Increase of US$1.00/bbl	Decrease of US$1.00/bbl
Increase (decrease) to fair value of commodity risk management contracts	$ (13,195)	$ 13,252	$ 5,405	$ (5,499)

Foreign exchange contracts

As at March 31, 2019, Athabasca had the following foreign exchange risk management contract in place to reduce its exposure to foreign currency risk on its August 2019 interest payment associated with the 2022 Notes.

Instrument	Period	Amount (US$)	Exchange rate (USD/CAD)
Forward swap contract	August 2019	$ 22,219	$ 1.3250

The following table summarizes the net loss on foreign exchange risk management contracts for the three months ended March 31, 2019 and 2018:

	Three months ended March 31,	
	2019	2018
Unrealized loss on foreign exchange risk management contracts	$ (2,340)	$ —
Realized gain on foreign exchange risk management contracts	1,615	—
LOSS ON FOREIGN EXCHANGE RISK MANAGEMENT CONTRACTS, NET	$ (725)	$ —

The net loss on foreign exchange risk management contracts is due to fluctuations in the USD/CAD forward exchange rates and the settlement of the February 2019 contract.

Commitments and Contingencies

The following table summarizes Athabasca's estimated future minimum commitments as at March 31, 2019 for the following five years and thereafter:

($ Thousands)	Remaining 2019	2020	2021	2022	2023	Thereafter	Total
Transportation and processing[(1)]	$ 89,871	$ 119,457	$ 108,248	$ 176,157	$ 217,973	$ 3,773,215	$ 4,484,921
Repayment of long-term debt[(1)]	—	—	—	601,200	—	—	601,200
Interest expense on long-term debt[(1)]	29,684	59,369	59,369	29,684	—	—	178,106
Purchase commitments and drilling rigs	4,141	—	—	—	—	—	4,141
TOTAL COMMITMENTS	$ 123,696	$ 178,826	$ 167,617	$ 807,041	$ 217,973	$ 3,773,215	$ 5,268,368

(1) Commitments which are denominated in US dollars were translated into Canadian dollars at the March 31, 2019 exchange rate of US$1.00 = C$1.3360.

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

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

Other Corporate Items

General and Administrative ("G&A")

($ Thousands, unless otherwise noted)	Three months ended March 31, 2019	2018
TOTAL GENERAL AND ADMINISTRATIVE	$ 4,949	$ 9,034
G&A per boe	$ 1.40	$ 2.47

During the three months ended March 31, 2019, Athabasca's G&A expenses decreased compared to the same period in the prior year primarily due to severances incurred in the first quarter of 2018 and lower 2019 employee costs as a result of the Company's staff reductions in the fourth quarter of 2018. The first quarter of 2019 G&A was also impacted by the adoption of IFRS 16 *Leases* which resulted in a decrease to G&A of $0.7 million.

Loss on Revaluation of Provisions and Other, Net

($ Thousands)	Three months ended March 31, 2019	2018
Contingent payment obligation loss	$ (1,782)	$ (26,265)
Capital-carry receivable gain	953	2,309
Other	—	1,743
LOSS ON REVALUATION OF PROVISIONS AND OTHER, NET	$ (829)	$ (22,213)

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

Income Taxes

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

The Company has approximately $3.1 billion in tax pools, including approximately $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.

Uncertainty around timing of future pipeline infrastructure due to regulatory and legislative delays is a significant risk to Athabasca and could have a material impact on future financial results. Additional information is available in Athabasca's AIF that is filed on the Company's SEDAR profile at www.sedar.com.

Off Balance Sheet Arrangements

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

Outstanding Share Data

As at March 31, 2019, there were 516.3 million common shares outstanding, an aggregate of 20.6 million restricted share units, performance share units and deferred shares units outstanding, and 8.5 million stock options outstanding. During the three months ended March 31, 2019, Athabasca issued 0.5 million common shares in respect of the Company's equity-settled share-based compensation plans.

As at May 7, 2019, there were 522.5 million common shares outstanding, an aggregate of 26.2 million restricted share units, performance share units and deferred shares units outstanding, and 9.8 million stock options outstanding.

SUMMARY OF QUARTERLY RESULTS

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

	2019	2018				2017		
($ Thousands, unless otherwise noted)	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	54.90	58.81	69.50	67.90	62.87	55.40	48.21	48.29
WTI (C$/bbl)	72.97	77.70	90.84	87.67	79.53	70.47	60.35	64.95
Western Canadian Select (C$/bbl)	56.62	25.36	61.75	62.89	48.77	54.87	47.76	49.99
Edmonton Par (C$/bbl)	66.41	42.75	81.90	80.60	72.06	69.02	56.62	61.92
Edmonton Condensate (C5+) (C$/bbl)	66.60	59.73	87.01	88.87	79.74	73.74	59.01	65.15
AECO (C$/GJ)	2.49	1.48	1.13	1.12	1.97	1.60	1.38	2.64
NYMEX Henry Hub (US$/MMBtu)	3.15	3.64	2.91	2.80	3.00	2.93	3.00	3.19
Foreign exchange (USD : CAD)	1.33	1.32	1.31	1.29	1.27	1.27	1.25	1.34
CONSOLIDATED								
Petroleum and natural gas production (boe/d)	39,206	37,984	40,612	37,658	40,572	42,064	36,133	36,574
Realized price (net of cost of diluent) ($/boe)	42.25	2.47	43.42	39.73	24.23	36.95	34.13	33.68
Petroleum and natural gas sales ($)	226,127	96,885	253,404	251,369	207,979	238,835	187,722	204,098
Operating Income (Loss) ($)(1)	58,602	(53,180)	83,703	46,719	16,876	65,002	52,358	43,787
Operating Netback ($/boe)(1)	16.77	(14.80)	23.21	13.01	4.65	17.25	15.58	13.28
Capital expenditures ($)	52,964	65,399	74,509	54,159	82,261	52,418	73,833	45,674
Capital Expenditures Net of Capital-Carry ($)(1)	31,756	46,042	52,389	38,888	56,661	33,236	67,741	32,181
LIGHT OIL DIVISION								
Petroleum and natural gas production (boe/d)	11,712	12,609	10,135	11,872	10,495	11,507	7,875	7,246
Realized price ($/boe)	41.53	32.27	46.43	42.68	44.65	40.10	36.83	41.11
Petroleum and natural gas sales ($)	43,778	37,434	43,294	46,107	42,182	42,456	26,680	27,111
Operating Income ($)(1)	31,280	22,121	29,795	30,936	24,292	26,696	13,748	16,391
Operating Netback ($/boe)(1)	29.67	19.07	31.95	28.64	25.72	25.22	18.98	24.85
Capital expenditures ($)	29,855	39,569	60,739	25,557	66,630	40,988	53,406	31,061
Capital Expenditures Net of Capital-Carry ($)(1)	8,647	20,212	38,619	10,286	41,030	21,806	47,314	17,568
THERMAL OIL DIVISION								
Bitumen production (bbl/d)	27,494	25,375	30,477	25,786	30,077	30,557	28,258	29,328
Bitumen sales volumes (bbl/d)	27,100	26,462	29,074	27,578	29,857	29,447	28,640	28,970
Realized bitumen price ($/bbl)	42.56	(11.74)	42.37	38.46	17.05	35.72	33.38	31.82
Blended bitumen sales ($)	182,349	59,451	210,110	205,262	165,797	196,379	161,042	176,987
Operating Income (Loss) ($)(1)	45,128	(84,544)	62,322	39,635	(6,744)	45,385	34,945	26,661
Operating Netback ($/bbl)(1)	18.50	(34.72)	23.30	15.79	(2.51)	16.75	13.27	10.11
Capital expenditures ($)	23,109	25,703	13,767	28,595	15,631	11,368	20,382	14,127
OPERATING RESULTS								
Cash flow from operating activities ($)	(18,572)	(2,253)	61,733	27,605	(3,241)	37,060	49,488	28,049
Adjusted Funds Flow ($)(1)	41,619	(75,296)	62,151	25,680	(6,360)	41,808	34,400	27,567
Net income (loss) ($)	206,796	(488,479)	31,419	(19,267)	(93,330)	(209,588)	5,113	24,233
Net income (loss) per share - basic ($)	0.40	(0.95)	0.06	(0.04)	(0.18)	(0.41)	0.01	0.05
BALANCE SHEET ITEMS								
Cash and cash equivalents ($)	272,240	73,898	128,340	93,293	128,915	163,321	174,076	179,611
Restricted cash ($)	106,385	111,056	114,216	114,212	111,778	113,406	113,372	113,853
Capital-carry receivable (discounted) ($)(2)	58,861	79,116	98,221	119,018	132,745	156,036	169,611	173,714
Total assets ($)	2,066,858	1,825,638	2,320,838	2,297,112	2,318,471	2,323,572	2,498,740	2,488,995
Long-term debt ($)(2)	570,411	581,140	546,505	554,279	541,460	526,206	523,782	541,199
Shareholders' equity ($)	1,172,954	965,949	1,452,946	1,418,587	1,434,345	1,524,610	1,731,546	1,723,735

(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 three months ended March 31, 2019, there were no changes to Athabasca's accounting policies or use of estimates in the preparation of the consolidated financial statements and the notes thereto, except as noted below. Refer to the December 31, 2018 audited consolidated financial statements for the Company for further guidance regarding Athabasca's accounting policies and use of estimates.

Changes in accounting policies

IFRS 16 *Leases*

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

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

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

During the three months ended March 31, 2019, interest expense increased by $0.4 million, depreciation increased by $0.5 million and general and administrative expense decreased by $0.7 million as a result of the adoption of IFRS 16. For the three months ended March 31, 2019, cash flows associated with the lease repayments of $1.0 million were allocated between operating and financing activities in the amounts of $0.4 million and $0.6 million, respectively, based on their interest and principal repayment components.

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

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

ADVISORIES AND OTHER GUIDANCE

Non-GAAP Financial Measures

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

The following table reconciles cash flow from operating activities in the consolidated financial statements for the three months ended March 31, 2019 and 2018 to Adjusted Funds Flow:

	Three months ended March 31,	
($ Thousands)	**2019**	**2018**
Cash flow from operating activities[1]	$ (18,572)	$ (3,241)
Changes in non-cash working capital	57,400	(6,571)
Settlement of provisions	2,791	3,452
ADJUSTED FUNDS FLOW[1]	$ 41,619	$ (6,360)

(1) The adoption of IFRS 16 *Leases* resulted in a $0.6 million increase in cash flow from operating activities and Adjusted Funds Flow in the first quarter of 2019.

Adjusted Funds Flow is not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS. The Adjusted Funds Flow measure allows management and others to evaluate the Company's ability to fund its capital programs and meet its ongoing financial obligations using cash flow internally generated from ongoing operating related activities. Adjusted Funds Flow per share is calculated as Adjusted Funds Flow divided by the applicable number of weighted average shares outstanding.

The Light Oil Operating Income and Light Oil Operating Netback measures in this MD&A are calculated by subtracting royalties, operating expenses and transportation & marketing expenses from petroleum and natural gas sales. The Light Oil Operating Netback measure is presented on a per boe basis. The Light Oil Operating Income and the Light Oil Operating Netback measures allow management and others to evaluate the production results from the Company's Light Oil assets. The table on page 8 reconciles Light Oil Operating Income to *Note 12 - Segmented Information* in the consolidated financial statements for the three months ended March 31, 2019.

The Operating Income (Loss) and Operating Netback measures in this MD&A with respect to the Leismer Project and Hangingstone Project are calculated by subtracting the cost of diluent blending, royalties, operating expenses and transportation & marketing expenses from blended bitumen sales. The Thermal Oil Operating Netback measure is presented on a per barrel basis of bitumen sales. The Thermal Oil Operating Income (Loss) and the Thermal Oil Operating Netback measures allow management and others to evaluate the production results from the Company's Thermal Oil assets. The table on page 12 reconciles Thermal Oil Operating Income (Loss) to *Note 12 - Segmented Information* in the consolidated financial statements for the three months ended March 31, 2019.

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 12 - Segmented Information* in the consolidated financial statements for the three months ended March 31, 2019.

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

The Consolidated Free Cash Flow measure in this MD&A is calculated by subtracting Capital Expenditures Net of Capital-Carry from Adjusted Funds Flow. The Light Oil Free Cash Flow measure in this MD&A is calculated by subtracting Light Oil Capital Expenditures Net of Capital-Carry from Light Oil Operating Income. The Thermal Oil Free Cash Flow measure in this MD&A is calculated by subtracting Thermal Oil Capital Expenditures from Thermal Oil Operating Income (Loss). These measures allow management and others to evaluate Athabasca's ability to generate funds to finance our operations and capital expenditures.

Comparative Figures

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

Internal Controls Update

Athabasca is required to comply with National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109"). NI 52-109 requires that Athabasca disclose in its interim MD&A any material weaknesses in Athabasca's internal control over financial reporting and/or any changes in Athabasca's internal control over financial reporting that occurred during the period that have materially affected, or are reasonably likely to materially affect, Athabasca's internal controls over financial reporting. Athabasca confirms that no material weaknesses or such changes were identified in Athabasca's internal controls over financial reporting during the first quarter of 2019.

Risk Factors

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

Operational risks

- the performance of the Company's assets;
- Athabasca's exploration and development budget and Athabasca's capital expenditure programs;
- failure to realize anticipated benefits of acquisitions or divestments;
- uncertainties inherent in estimating quantities of Proved Reserves, Probable Reserves and Contingent Resources;
- the timing of certain of Athabasca's operations and projects, including the commencement of its planned Thermal Oil Division development projects, the exploration and development of Athabasca's Light Oil assets and the levels and timing of anticipated production;
- dependence upon Murphy as a working interest participant in its Light Oil assets and as operator of the Greater Kaybob assets;
- risks and uncertainties inherent in Athabasca's operations, including those related to exploration, development and production of bitumen, crude oil, natural gas and natural gas liquids reserves and resources;
- risks related to gathering and processing facilities and pipeline systems;
- reliance on third party infrastructure;
- risks associated with events of force majeure; and
- expiration of leases and permits or the failure of Athabasca or the holder of certain licenses, leases or permits to meet specific requirements of such licenses, leases or permits.

Planning risks

- the business strategy, objectives and business strengths of Athabasca;
- Athabasca's growth strategy and opportunities;
- Athabasca's plans to submit additional regulatory applications;
- Athabasca's drilling plans and plans and results regarding the completion of wells that have been drilled and other exploration and development activities;
- failure to accurately estimate abandonment and reclamation costs; and
- the potential for management estimates and assumptions to be inaccurate.

Financial and market risks

- general economic, market and business conditions in Canada, the United States and globally;
- future market prices for crude oil, natural gas, condensate and bitumen blend;
- Canadian heavy and light oil export capacity constraints and the resulting impact on realized pricing;
- Athabasca's projections of commodity prices, costs and netbacks;
- the substantial capital requirements of Athabasca's projects and the Company's ability to raise capital;
- risk of reduced capital availability due to environmental and climate related reputational issues for industry;
- the potential for future joint venture arrangements;
- insurance risks;
- hedging risks;
- variations in foreign exchange and interest rates;
- risks related to the Credit Facility, the Letter of Credit Facility, the Unsecured Letter of Credit Facility and the 2022 Notes;
- risks related to the Common Shares; and
- Athabasca's information and computer systems and exposure to cyber-security breaches.

Legal and compliance risks

- the regulatory framework governing royalties, taxes, environmental matters and foreign investment in the jurisdictions in which Athabasca conducts and will conduct its business;
- risks related to Athabasca's filings with taxation authorities, including the risk of tax related reviews and reassessments;
- actions taken by the American administration on the imposition of taxes on the importation of goods into the United States;
- aboriginal claims;
- risks associated with establishing and maintaining systems of internal controls; and
- inaccuracy of forward-looking information.

For additional information regarding the risks and uncertainties to which the Company and its business are subject, please see the information under the headings "Forward Looking Information" below, and under the headings "Forward Looking Statements" and "Risk Factors" in the Company's most recent AIF, on the Company's SEDAR profile at www.sedar.com.

Forward Looking Information

This MD&A contains forward-looking information that involves various risks, uncertainties and other factors. All information other than statements of historical fact is forward-looking information. The use of any of the words "anticipate," "plan," "continue", "estimate", "expect", "may", "will", "project", "target", "should", "believe", "predict", "pursue" and "potential" and similar expressions are intended to identify forward-looking information. The forward-looking information is not historical fact, but rather is based on the Company's current plans, objectives, goals, strategies, estimates, assumptions and projections about the Company's industry, business and future financial results. This information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. No assurance can be given that these expectations will prove to be correct and such forward-looking information included in this MD&A should not be unduly relied upon. This information speaks only as of the date of this MD&A. In particular, this MD&A may contain forward-looking information pertaining to the following: the Company's future growth outlook and how that growth outlook is funded; the benefits expected to be realized by the Company from the 2022 Notes and the Credit Facility; the benefits expected to be realized by the Company from the Leismer/Corner acquisition; the timing by which the Corporation expects to achieve sustainable free cash flow generation, cash and cash equivalents and liquidity, for certain future periods; expectations with respect to future production hedging levels; estimates of corporate, Thermal Oil and Light Oil production levels and base decline rates; the in-service dates of the Trans Mountain pipeline expansion and 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 2019 and beyond; the Company's estimate future minimum capital commitments; the future allocation of capital; and other matters.

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

With respect to forward-looking information contained in this MD&A, assumptions have been made regarding, among other things: that Athabasca and its security holders will obtain the anticipated benefits from the 2022 Notes and the Credit Facility; commodity prices, including for petroleum, natural gas and blended bitumen; the regulatory framework governing royalties, taxes and environmental matters in the jurisdictions in which the Company conducts and will conduct business and the effects that such regulatory framework will have on the Company, including on the Company's financial condition and results of operations; the Company's financial and operational flexibility; the Company's financial sustainability; Athabasca's cash flow break-even commodity price; the Company's ability to obtain qualified staff and equipment in a timely and cost-efficient manner; the applicability of technologies for the recovery and production of the Company's reserves and resources; future capital expenditures to be made by the Company; future sources of funding for the Company's capital programs; the Company's future debt levels; future production levels; the Company's ability to obtain financing and/or enter into joint venture arrangements, on acceptable terms; operating costs; compliance of counterparties with the terms of contractual arrangements; impact of increasing competition globally; collection risk of outstanding accounts receivable from third parties; geological and engineering estimates in respect of the Company's reserves and resources; recoverability of reserves and resources; the geography of the areas in which the Company is conducting exploration and development activities and the quality of its assets.

Actual results could differ materially from those anticipated in this forward-looking information as a result of the risk factors set forth in the Company's most recent AIF available on SEDAR at www.sedar.com, including, but not limited to: weakness in the oil and gas industry; prices, markets and marketing; adverse changes in general economic and market conditions; climate change; political uncertainty & terrorist attacks; regulatory; gathering and processing, facilities, pipeline systems and rail; statutes and regulations regarding the environment; anticipated benefits of acquisitions and dispositions; abandonment and reclamation costs; ability to finance; state of the capital markets; stage of development; royalty regimes; additional funding requirements; foreign exchange rates and interest rates; uncertainties inherent in estimating reserves and resources volumes; hedging; operational dependence; diluent supply; operating costs; hydraulic fracturing; future acquisition and joint venture activities; exploration, development and production risks; third party credit risk; conflicts of interest; aboriginal claims; reliance on key personnel and operators; financial assurances; inability to utilize the most advanced technologies; changing demand for oil and natural gas products; tax reassessments or changes to income tax laws; need to replace reserves; environmental and health and safety risks and hazards; management estimates and assumptions; liability management; seasonality and weather conditions; unexpected events; internal controls; insurance; litigation; natural gas overlying bitumen resources; competition; chain of title; breaches of confidentiality; new industry related activities or new geographical areas; cyber-security; risks related to our indebtedness; risks related to the common shares.

In addition, information and statements in this MD&A relating to "Reserves" and "Resources" are deemed to be forward-looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and that the reserves and resources described can be profitably produced in the future. Certain assumptions related to the Company's Reserves and Resources are contained in the report of McDaniel & Associates Consultants Ltd. ("McDaniel") evaluating Athabasca's Proved Reserves, Probable Reserves and Contingent Resources as at December 31, 2018 (which is respectively referred to herein as the "McDaniel Report").

The risks and uncertainties referred to above are described in more detail in Athabasca's most recent AIF, which is available on the Company's SEDAR profile at www.sedar.com. Readers are cautioned that the foregoing list of risk factors should not be construed as exhaustive. The forward-looking information included in this MD&A is expressly qualified by this cautionary statement and is made as of the date of this MD&A. The Company does not undertake any obligation to publicly update or revise any forward-looking information except as required by applicable securities laws.

The Company's financial condition and results of operations discussed in this MD&A will not necessarily be indicative of the Company's future performance, particularly considering that many of the Company's activities are currently in the early stages of their planned exploration and/or development.

Reserves and Resource Information

The McDaniel Report was prepared using the assumptions and methodology guidelines outlined in the COGE Handbook and in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities,* effective December 31, 2018. There are numerous uncertainties inherent in estimating quantities of bitumen, crude oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth above are estimates only. In general, estimates of economically recoverable reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially. For those reasons, estimates of the economically recoverable reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. There is no certainty that it will be commercially viable to produce any portion of the resources. Reserves figures described herein have been rounded to the nearest MMbbl or MMboe. Contingent Resources described herein have been rounded to the nearest billion barrels. For additional information regarding the consolidated reserves and resources of the Company as evaluated by McDaniel in the McDaniel Report, please refer to the Company's AIF that is available on SEDAR at www.sedar.com.

Oil and Gas Information

"Boe" may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent (6 Mcf: 1 bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Drilling Locations

The 1,000 Duvernay drilling locations referenced on page 6 of this MD&A include: 50 proved undeveloped or non-producing locations and 35 probable undeveloped locations for a total of 85 booked locations with the balance being unbooked locations. The 200 Montney drilling locations referenced on page 6 of this MD&A include: 77 proved undeveloped locations and 12 probable undeveloped locations for a total of 89 booked locations with the balance being unbooked locations. Proved undeveloped locations and probable undeveloped locations are booked and derived from the Company's most recent independent reserves evaluation as prepared by McDaniel as of December 31, 2018 and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal management estimates. Unbooked locations do not have attributed reserves or resources (including contingent or prospective). Unbooked locations have been identified by management as an estimation of Athabasca's multi-year drilling activities expected to occur over the next two decades based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, oil and natural gas prices, provincial fiscal and royalty policies, costs, actual drilling results, additional reservoir information that is obtained and other factors.

Definitions

"Best Estimate" is a classification of estimated resources described in the COGE Handbook as being considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the Best Estimate. If probabilistic methods are used, there should be a 50% probability (P50) that the quantities actually recovered will equal or exceed the Best Estimate**.**

"**Contingent Resources**" are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include such factors as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "Contingent Resources" the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources may be divided into the following project maturity sub-classes: "Development Pending" is assigned to Contingent Resources for a particular project where resolution of the final conditions for development is being actively pursued (high chance of development); "Development On Hold" is assigned to Contingent Resources for a particular project where there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator; "Development Unclarified" is assigned to Contingent Resources for a particular project where evaluation is incomplete and there is ongoing activity to resolve any risks or uncertainties or which require significant further appraisal to clarify potential for development and where contingencies have yet to be defined; "Development Not Viable" is assigned to Contingent Resources for a particular project where no further data acquisition or evaluation is currently planned and there is a low chance of development. As at December 31, 2018, the Company reported Contingent Resources on a risked and unrisked basis located in its Leismer and Corner asset areas in the Development Pending project maturity sub-class and for the Dover West Sands asset area in the Development on Hold project maturity sub-class.

"Proved Reserves" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated Proved Reserves.

"Probable Reserves" are those additional reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved Reserves plus Probable Reserves.

"Reserve Life Index" is a measure of the estimated length of time it will take to deplete the Company's oil and gas reserves (typically reported in number of years).

"**Risked**" or **"risked"** means the applicable reported volumes or revenues have been risked (or adjusted) based on the chance of commerciality of such resources in accordance with the COGE Handbook. In accordance with the COGE Handbook for contingent resources, the chance of commerciality is solely based on the chance of development based on all contingencies required for the re-classification of the contingent resources as reserves being resolved. Therefore, risked reported volumes and values of contingent resources reflect the risking (or adjustment) of such volumes or values based on the chance of development of such resources.

"**Unrisked**" or **"unrisked"** means applicable reported volumes or values of resources have not been risked (or adjusted) based on the chance of commerciality of such resources. In accordance with the COGE Handbook for contingent resources, the chance of commerciality is solely based on the chance of development based on all contingencies required for the re-classification of the contingent resources as reserves being resolved. Therefore, unrisked reported volumes and values of contingent resources do not reflect the risking (or adjustment) of such volumes or values based on the chance of development of such resources.

Abbreviations

AECO	physical storage and trading hub for natural gas on the TransCanada Alberta transmission system which is the delivery point for various benchmark Alberta index prices.
bbl	barrel
bbl/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
C$	Canadian Dollars
COGE	Canadian Oil and Gas Evaluation
GAAP	Generally Accepted Accounting Principles
LIBOR	London interbank offered rate
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMbbl	millions of barrels
MMboe	millions of barrels of oil equivalent
MMBtu	million British thermal units
NYMEX	New York Mercantile Exchange
SAGD	steam assisted gravity drainage
US$	United States Dollars
WTI	West Texas Intermediate
WCS	Western Canadian Select