Management's Discussion and Analysis

Q1 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 May 9, 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 months ended March 31, 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 an intermediate producer with strong and competitive investment opportunities across its portfolio in the current operating environment. The Company has tremendous leverage to oil prices and is focused on maximizing profitability through measured activity in Light Oil and ongoing Thermal Oil optimization. The strategy is guided by:

- Light Oil - Montney at Placid ("Greater Placid") and Duvernay at Kaybob ("Greater Kaybob"): Defined and Material Margin Growth
- Thermal Oil: Low Decline, Long-Life, Free Cash Flow Generating Assets
- Financial Sustainability: Increasing Margins, 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 oil-weighted margins and significant free cash flow to maximize shareholder returns and provide strategic optionality into the future.

HIGHLIGHTS FOR THE QUARTER ENDED MARCH 31, 2018

Light Oil Division

- Production of 10,495 boe/d (50% liquids), representing growth of 207% over the first quarter of 2017.
- 12 (gross) wells placed on production including five at Greater Placid and seven at Greater Kaybob.
- Realized a first quarter 2018 operating netback(1) of $25.72/boe with operating expenses of $8.88/boe, up 15% and down 42%, respectively, compared to the first quarter of 2017.
- Generated operating income(1) of $24.3 million, an increase of 254% over the prior year first quarter.

Thermal Oil Division

- Production of 30,007 bbl/d, an increase of 29% over the prior year first quarter reflecting a full quarter impact of the Leismer Corner Acquisition(2).
- Advanced planned optimization and debottlenecking initiatives at Leismer to maximize production and facility performance, and support future sustaining pad development.
- Reduced operating expenses by 24% from the first quarter of 2017 to $13.53/bbl.
- Generated operating income(1) of $4.9 million at Leismer, and an operating loss(1) of $11.6 million at Hangingstone. Margins in the first quarter were significantly impacted by a 67% year over year increase in the Western Canadian Select heavy oil differential and higher product basis spreads as a result of heavy oil pipeline constraints.

Corporate

- Production of 40,572 boe/d, an increase of 52% over the prior year first quarter.
- Consolidated Operating Income(1) of $16.9 million and Adjusted Funds Flow(1) of ($6.4) million.
- Reduction in consolidated operating expenses per boe of 29% compared to the first quarter of 2017.
- Continued balance sheet strength with $129 million of cash and cash equivalents, a $120 million credit facility (available credit of $62 million) and a $138 million (undiscounted) capital-carry balance.

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.
(2) As defined on page 9.

FINANCIAL & OPERATIONAL HIGHLIGHTS

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

($ Thousands, unless otherwise noted)[1]	Three months ended March 31, 2018	2017
CONSOLIDATED		
Petroleum and natural gas volumes (boe/d)	40,572	26,737
Operating Income[1][2]	$ 16,876	$ 19,204
Operating Netback[1][2] ($/boe)	$ 4.65	$ 7.99
Capital expenditures[3]	$ 82,261	$ 90,124
Capital expenditures net of capital-carry[1][3]	$ 56,661	$ 79,444
LIGHT OIL DIVISION		
Oil, condensate and natural gas liquids (bbl/d)	5,243	1,961
Natural gas (Mcf/d)	31,511	8,760
Petroleum and natural gas volumes (boe/d)	10,495	3,421
Operating Income[1]	$ 24,292	$ 6,863
Operating Netback[1] ($/boe)	$ 25.72	$ 22.28
Capital expenditures	$ 66,630	$ 77,646
Capital expenditures net of capital-carry[1]	$ 41,030	$ 66,966
THERMAL OIL DIVISION		
Bitumen production (bbl/d)	30,077	23,316
Operating Income (Loss)[1]	$ (6,744)	$ 10,050
Operating Netback[1] ($/bbl)	$ (2.51)	$ 4.80
Capital expenditures[3]	$ 15,631	$ 10,868
CASH FLOW AND FUNDS FLOW		
Cash flow from operating activities	$ (3,241)	$ (52,896)
per share (basic)	$ (0.01)	$ (0.11)
Adjusted Funds Flow[1]	$ (6,360)	$ (1,649)
per share (basic)	$ (0.01)	$ —
NET LOSS AND COMPREHENSIVE LOSS		
Net loss and comprehensive loss	$ (93,330)	$ (29,162)
per share (basic and diluted)	$ (0.18)	$ (0.06)
COMMON SHARES OUTSTANDING		
Weighted average shares outstanding (basic and diluted)	510,191,864	472,157,006

As at ($ Thousands)	March 31, 2018	December 31, 2017
LIQUIDITY AND INDEBTEDNESS		
Cash and cash equivalents	$ 128,915	$ 163,321
Restricted cash	$ 111,778	$ 113,406
Capital-carry receivable (current and long-term portion - undiscounted)	$ 138,423	$ 164,023
Face value of long-term debt[4]	$ 580,545	$ 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.
(3) 2017 capital expenditures excludes the cost of the Leismer Corner Acquisition (see page 9).
(4) The face value of the US dollar denominated 2022 Notes is US$450 million. As at March 31, 2018, the 2022 Notes were translated into Canadian dollars at the period end exchange rate of US$1.00 = C$1.2901.

BUSINESS ENVIRONMENT

Canadian producers were faced with unprecedented volatility in Canadian heavy oil differentials and basis spreads in early 2018 due to pipeline capacity constraints which impacted short term profitability and financial results. Western Canadian Select ("WCS") differentials averaged US$24.32/bbl during the first quarter of 2018 and peaked in excess of US$30/bbl, averaging 67% (~US$10/bbl) higher than the first quarter of 2017. Product basis spreads which reflect quality differentials and apportionment were also volatile. Athabasca's dilbit sales received a C$6.62/bbl discount to the WCS benchmark, compared to C$3.88/bbl in the fourth quarter of 2017.

Adjusting for this macro volatility the Company estimates that it would have realized an incremental $38 million in Thermal Oil operating income in the first quarter of 2018 assuming a US$5/bbl improvement in WCS differentials and normalized basis spreads.

Since the first quarter of 2018, WCS pricing has improved considerably, with strip prices tightening to approximately US$20/bbl for the balance of the year. The global outlook for crude oil also continues to strengthen, supporting Athabasca's oil-weighted portfolio. The Company is a net consumer of gas and is a beneficiary of the current 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 transportation costs and quality differentials relative to the benchmark prices.

Benchmark prices

	Three months ended March 31,		
(Average)	2018	2017	Change
Crude oil:			
West Texas Intermediate (WTI) (US$/bbl)[1]	$ 62.87	$ 51.91	21 %
West Texas Intermediate (WTI) (C$/bbl)[1]	$ 79.53	$ 68.52	16 %
Western Canadian Select (WCS) (C$/bbl)[2]	$ 48.77	$ 49.34	(1)%
Edmonton Par (C$/bbl)[3]	$ 72.06	$ 63.87	13 %
Edmonton Condensate (C5+) (C$/bbl)[4]	$ 79.74	$ 68.73	16 %
WCS Differential:			
WTI vs. WCS (US$/bbl)	$ (24.32)	$ (14.53)	(67)%
WTI vs. WCS (C$/bbl)	$ (30.76)	$ (19.18)	(60)%
Natural gas:			
AECO (C$/GJ)[5][6]	$ 1.97	$ 2.55	(23)%
NYMEX Henry Hub (US$/MMBtu)[6]	$ 3.00	$ 3.32	(10)%
Foreign exchange:			
USD : CAD	1.27	1.32	(4)%

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)	38,500 - 41,000
Liquids weighting (%)	~87%
Adjusted Funds Flow(1)	$145
Operating Income(1)	$255
Light Oil (net)	
Production (boe/d)	10,500 - 11,500
Operating Income(1)	$125
Capital expenditures net of capital-carry(1)	$70
Thermal Oil	
Bitumen production (bbl/d)	28,000 - 29,500
Operating Income(1)	$130
Capital expenditures	$70
Commodity assumptions	
WTI (US$/bbl)	$65.00
WCS differential (US$/bbl)	$20.00
AECO Gas (C$/Mcf)	$1.50
FX (US$/C$)	0.77

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

Athabasca’s 2018 operational outlook is unchanged with a $140 million capital budget and production guidance of 38,500 - 41,000 boe/d (87% liquids). Annual adjusted funds flow guidance has been increased to $145 million (from $125 million) on stronger underlying commodity prices which are closely aligned to strip prices.

The Company forecasts 2018 Light Oil operating income of $125 million. The $70 million capital program includes $40 million for Greater Placid and $387 million ($30 million net) for Greater Kaybob. Second half activity levels in the Montney will be assessed mid-year.

With the strength in oil prices and improved differential outlook the Company now forecasts 2018 Thermal Oil operating income of $130 million (up from $100 million) with a $70 million capital program.

Athabasca’s outlook and financial sustainability are underpinned by high margin Light Oil growth, low break-even costs at Leismer, strong capital discipline, and an active commodity hedging program targeting up to 50% of near term production. Athabasca has secured long term egress to multiple end markets with capacity on the Kinder Morgan Trans Mountain Expansion Project ("TMX Pipeline") and TransCanada Keystone XL ("Keystone XL Pipeline").

Athabasca provides investors excellent exposure to improving oil prices with low total leverage with estimated unhedged funds flow sensitivity of ~$80 million for each incremental US$5/bbl increase in WTI.

Midstream Process

Athabasca is exploring monetization options for its extensive Thermal Oil infrastructure. The Company believes that current timing is favorable following the integration of Leismer and strong market precedent transactions. A process is underway to explore a wide range of alternatives for this infrastructure which could include a sale, partnership or joint venture. The infrastructure will remain a strategic asset for future growth initiatives at Leismer and Corner.

The Company maintains flexibility for use of potential proceeds which could include bolstering liquidity and/or debt reduction, investing in projects across its asset base that will generate attractive returns for shareholders, and initiating a share buyback program.

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, 2018	2017
VOLUMES		
Oil and condensate (bbl/d)	4,196	1,763
Natural gas (Mcf/d)	31,511	8,760
Natural gas liquids (bbl/d)	1,047	198
Bitumen production (bbl/d)	30,077	23,316
Total (boe/d)	40,572	26,737

($ Thousands, unless otherwise noted)	Three months ended March 31, 2018	2017
Petroleum and natural gas sales	$ 200,384	$ 151,502
Realized gain (loss) on commodity risk management contracts	(672)	2,291
Royalties	(3,104)	(1,826)
Cost of diluent	(119,988)	(77,949)
Operating expenses	(44,677)	(41,815)
Transportation and marketing	(15,067)	(12,999)
Consolidated Operating Income(1)	$ 16,876	$ 19,204
REALIZED PRICES		
Oil and condensate ($/bbl)	$ 69.87	$ 60.08
Natural gas ($/Mcf)	1.23	2.66
Natural gas liquids ($/bbl)	50.06	20.59
Blended bitumen sales ($/bbl)	42.15	46.02
Realized price (net of cost of diluent) ($/boe)	22.14	30.63
Realized gain (loss) on commodity risk management contracts ($/boe)	(0.19)	0.95
Royalties ($/boe)	(0.85)	(0.76)
Operating expenses ($/boe)	(12.30)	(17.42)
Transportation and marketing ($/boe)	(4.15)	(5.41)
CONSOLIDATED OPERATING NETBACK(1) ($/boe)	$ 4.65	$ 7.99

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

Consolidated Segments Loss

($ Thousands)	Three months ended March 31, 2018	2017
Consolidated Operating Income(1)	$ 16,876	$ 19,204
Unrealized gain (loss) on commodity risk management contracts	(3,492)	7,214
Depletion and depreciation	(38,448)	(19,283)
Acquisition expense	—	(7,647)
Loss on sale of assets	—	(407)
Exploration expense and other	(306)	(168)
CONSOLIDATED SEGMENTS LOSS	$ (25,370)	$ (1,087)

(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, 2018	2017
Light Oil Division	$ 66,630	$ 77,646
Thermal Oil Division[1]	15,631	10,868
Corporate assets	—	1,610
TOTAL CAPITAL EXPENDITURES[2]	$ 82,261	$ 90,124
Less: Greater Kaybob capital-carry	(25,600)	(10,680)
TOTAL CAPITAL EXPENDITURES NET OF CAPITAL-CARRY[3]	$ 56,661	$ 79,444

(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 months ended March 31, 2018, capital expenditures include $3.1 million of capitalized staff costs (March 31, 2017 - $2.1 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 strategic 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 balance of the capital-carry at March 31, 2018 is $138.4 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 March 31, 2018	2017
SALES VOLUMES		
Oil and condensate (bbl/d)	4,196	1,763
Natural gas (Mcf/d)	31,511	8,760
Natural gas liquids (bbl/d)	1,047	198
Total (boe/d)	10,495	3,421
Consisting of:		
Greater Placid area (boe/d)	8,213	2,016
% liquids	46%	62%
Greater Kaybob area (boe/d)	2,282	1,405
% liquids	65%	51%

($ Thousands, unless otherwise noted)	Three months ended March 31, 2018	2017
Petroleum and natural gas sales	$ 34,587	$ 11,999
Royalties	(1,912)	(421)
Operating and transportation expenses	(8,383)	(4,715)
Light Oil Operating Income[(1)]	$ 24,292	$ 6,863
REALIZED PRICES		
Oil and condensate ($/bbl)	$ 69.87	$ 60.08
Natural gas ($/Mcf)	1.23	2.66
Natural gas liquids ($/bbl)	50.06	20.59
Realized price ($/boe)	36.62	38.97
Royalties ($/boe)	(2.02)	(1.37)
Operating and transportation expenses ($/boe)	(8.88)	(15.32)
LIGHT OIL OPERATING NETBACK[(1)] ($/boe)	$ 25.72	$ 22.28

(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 10,495 boe/d during the first quarter of 2018, an increase of 207% compared to the first quarter of 2017. Production growth year over year is primarily a result of continued development with 21 (gross) Montney and 18 (gross) Duvernay wells tied-in throughout 2017 and the first quarter of 2018, partially offset by shut-in production for offsetting completion activities in Greater Placid.

Athabasca's Light Oil Operating Netback was $25.72/boe in the first quarter of 2018, a 15% increase from the prior year first quarter. The increase was primarily due to higher oil and condensate prices and lower per boe operating costs, partially offset by lower realized gas prices. Light Oil operating and transportation expenses per boe have trended down significantly year over year with higher production volumes resulting in economies of scale over fixed costs, and averaged $8.88/boe in the first quarter of 2018.

As a result of higher production and higher netbacks, Athabasca generated Light Oil operating income of $24.3 million in the first quarter of 2018, a 254% increase over the first quarter of 2017.

Light Oil Segment Income

($ Thousands)	Three months ended March 31, 2018	2017
Light Oil Operating Income[1]	$ 24,292	$ 6,863
Depletion and depreciation	(16,700)	(4,610)
Loss on sale of assets	—	(101)
Exploration expense and other	(2)	(31)
LIGHT OIL SEGMENT INCOME	$ 7,590	$ 2,121

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

Depletion and depreciation of oil and gas assets increased $12.1 million in the first quarter of 2018, 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, 2018	2017
Greater Placid		
Drilling, completion and equipping	$ 29,763	$ 46,430
Facilities	1,133	18,131
Land acquisitions and other	2,055	79
	32,951	64,640
Greater Kaybob		
Drilling, completion and equipping	29,461	12,385
Facilities	4,395	465
Land acquisitions and other	(177)	156
	33,679	13,006
TOTAL LIGHT OIL CAPITAL EXPENDITURES[1]	$ 66,630	$ 77,646
Less: Greater Kaybob capital-carry	(25,600)	(10,680)
TOTAL CAPITAL EXPENDITURES NET OF CAPITAL-CARRY[2]	$ 41,030	$ 66,966

(1) For the three months ended March 31, 2018, capital expenditures include $1.4 million of capitalized staff costs (March 31, 2017 - $1.4 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 months ended March 31, 2018 and 2017:

Well activity[1]	Three months ended March 31, 2018 Gross	Net	Three months ended March 31, 2017 Gross	Net
Greater Placid				
Wells drilled	4	2.8	10	7.0
Wells completed	5	3.5	9	6.3
Wells brought on production	5	3.5	7	4.9
Greater Kaybob				
Wells drilled	13	3.9	6	1.8
Wells completed	5	1.5	2	0.6
Wells brought on production	7	2.1	2	0.6

(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 on production and tied-in to permanent facilities.

Throughout the first quarter of 2018, Athabasca advanced its 2017/18 winter drilling program in Greater Placid. The Company rig released four (gross) wells of a six (gross) well pad and completed and brought on production five (gross) wells.

In Greater Kaybob, a total of 13 (gross) Duvernay wells were rig released and seven (gross) Duvernay wells were brought on production in the first quarter. Including recovery of the capital-carry, Athabasca's net cash outflow from capital expenditures in Greater Kaybob was $8.1 million during the quarter ended March 31, 2018.

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 Statoil ASA (collectively "Statoil"). The acquired assets include the operating Leismer Thermal Oil Project (the "Leismer Project"), the delineated Corner exploration area 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 bookings 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 area has Proved plus Probable Reserves bookings 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, 300,000 barrels of storage capacity at the Cheecham Terminal and 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 TMX Pipeline expansion and 10,000 bbl/d of blended bitumen capacity on the Keystone XL Pipeline which will provide the Company with exposure to long-term global oil demand growth.

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 and $250.0 million over the four year term. No amounts were paid by Athabasca in respect of the annual contingent payment obligation for the year ended December 31, 2017.

Athabasca also operates the Hangingstone Thermal Oil Project (the “Hangingstone Project"), a SAGD oil sands project with a design capacity of 12,000 bbl/d. Hangingstone has Proved plus Probable Reserves bookings 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 March 31, 2018	2017
VOLUMES		
Bitumen production (bbl/d)	21,021	14,764
Bitumen sales (bbl/d)	21,049	14,635
Blended bitumen sales (bbl/d)	30,669	21,414

($ Thousands, unless otherwise noted)	Three months ended March 31, 2018	2017
Blended bitumen sales	$ 115,441	$ 89,027
Cost of diluent	(84,137)	(49,733)
Total bitumen sales	31,304	39,294
Royalties	(857)	(949)
Operating expenses - non-energy	(13,817)	(13,234)
Operating expenses - energy	(6,498)	(4,877)
Transportation and marketing	(5,280)	(3,561)
Leismer Operating Income(1)(2)	$ 4,852	$ 16,673
REALIZED PRICE		
Blended bitumen sales ($/bbl)	$ 41.82	$ 46.19
Bitumen sales ($/bbl)	$ 16.52	$ 29.83
Royalties ($/bbl)	(0.45)	(0.72)
Operating expenses - non-energy ($/bbl)	(7.29)	(10.05)
Operating expenses - energy ($/bbl)	(3.43)	(3.70)
Transportation and marketing ($/bbl)	(2.79)	(2.70)
LEISMER OPERATING NETBACK(1)(2) ($/bbl)	$ 2.56	$ 12.66

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

For the three months ended March 31, 2018, Athabasca averaged 21,021 bbl/d of bitumen production at Leismer compared to 14,764 bbl/d during the same period in the prior year. The production increase is a result of the Leismer Corner Acquisition which was completed on January 31, 2017.

Leismer Operating Netback was $2.56/bbl in the first quarter of 2018, a decrease of 80% from the first quarter of 2017. The decrease was due to lower realized pricing for bitumen sales partially offset by lower royalties and operating expenses per bbl. Lower realized bitumen pricing was primarily a result of the significant expansion of WCS differentials and product basis spreads, and a stronger Canadian dollar in the first quarter of 2018, which more than offset the benefit of stronger WTI prices.

Seasonality has an impact on the Thermal Oil business. Historically, the heavy oil differential (the price difference between WTI and WCS) tends to widen in winter months due to lower demand for gasoline and asphalt. Dilution costs are also generally higher during the winter as more diluent is required to meet pipeline specifications.

Compared to the same period in the prior year, operating expenses per bbl decreased by 22% to $10.72/bbl during the three months ended March 31, 2018. The decline was primarily due to lower non-energy operating expenses as a result of post-acquisition optimization of field operations, as well as lower natural gas prices which reduced energy operating costs. The Company continues to optimize capital and operating expenses to maximize profitability of the Leismer Project.

Operating Income at Leismer was $4.9 million in the first quarter of 2018, a reduction from $16.7 million in the prior year primarily due to lower realized pricing as discussed above. A scheduled turnaround commenced in late April and is expected to be completed in May. The Company estimates that the turnaround will impact annual average volumes by approximately 1,000 bbl/d.

Hangingstone Operating Results

	Three months ended March 31, 2018	Three months ended March 31, 2017
VOLUMES		
Bitumen production (bbl/d)	9,056	8,552
Bitumen sales (bbl/d)	8,808	8,622
Blended bitumen sales (bbl/d)	13,035	12,266

($ Thousands, unless otherwise noted)	Three months ended March 31, 2018	Three months ended March 31, 2017
Blended bitumen sales	$ 50,356	$ 50,476
Cost of diluent	(35,851)	(28,216)
Total bitumen sales	14,505	22,260
Royalties	(335)	(456)
Operating expenses - non-energy	(11,190)	(13,703)
Operating expenses - energy	(4,846)	(5,579)
Transportation and marketing	(9,730)	(9,145)
Hangingstone Operating Loss(1)	$ (11,596)	$ (6,623)
REALIZED PRICE		
Blended bitumen sales ($/bbl)	$ 42.92	$ 45.72
Bitumen sales ($/bbl)	$ 18.30	$ 28.69
Royalties ($/bbl)	(0.42)	(0.59)
Operating expenses - non-energy ($/bbl)	(14.12)	(17.66)
Operating expenses - energy ($/bbl)	(6.11)	(7.19)
Transportation and marketing ($/bbl)	(12.27)	(11.79)
HANGINGSTONE OPERATING NETBACK(1) ($/bbl)	$ (14.62)	$ (8.54)

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

For the three months ended March 31, 2018, Hangingstone averaged 9,056 bbl/d of bitumen production, an increase of 6% compared to the same period in the prior year with production from continued steam chamber development partially offset by facility maintenance in the quarter.

The Hangingstone Operating Netback was $(14.62)/bbl in the first quarter of 2018 compared to $(8.54)/bbl during the same period in 2017. The decrease in Operating Netback was primarily a result of lower realized pricing for bitumen sales, partially offset by lower operating expenses per bbl. Lower realized bitumen pricing was primarily a result of the significant expansion of WCS differentials and product basis spreads, and a stronger Canadian dollar in the first quarter of 2018, which more than offset the benefit of stronger WTI prices.

Seasonality has an impact on the Thermal Oil business. Historically, the heavy oil differential (the price difference between WTI and WCS) tends to widen in winter months due to lower demand for gasoline and asphalt. Dilution costs are also generally higher during the winter as more diluent is required to meet pipeline specifications.

Compared to the same period in the prior year, operating expenses per bbl decreased by 19% to $20.23/bbl. The decrease was primarily due to lower non-energy operating expenses as a result of continued optimization of field operations and higher production. In addition, energy operating expenses were lower during the first quarter of 2018 as a result of lower natural gas prices.

The Hangingstone Operating Loss of $11.6 million increased by $5.0 million compared to the first quarter of 2017 primarily due to lower realized pricing as discussed above.

Consolidated Thermal Oil Operating Results

	Three months ended March 31, 2018	2017
VOLUMES		
Bitumen production (bbl/d)	30,077	23,316
Bitumen sales (bbl/d)	29,857	23,257
Blended bitumen sales (bbl/d)	43,704	33,680

($ Thousands, unless otherwise noted)	Three months ended March 31, 2018	2017
Blended bitumen sales	$ 165,797	$ 139,503
Cost of diluent	(119,988)	(77,949)
Total bitumen sales	45,809	61,554
Royalties	(1,192)	(1,405)
Operating expenses - non-energy	(25,007)	(26,937)
Operating expenses - energy	(11,344)	(10,456)
Transportation and marketing	(15,010)	(12,706)
Thermal Oil Operating Income (Loss)[1]	$ (6,744)	$ 10,050
REALIZED PRICE		
Blended bitumen sales ($/bbl)	$ 42.15	$ 46.02
Bitumen sales ($/bbl)	$ 17.05	$ 29.41
Royalties ($/bbl)	(0.44)	(0.67)
Operating expenses - non-energy ($/bbl)	(9.31)	(12.87)
Operating expenses - energy ($/bbl)	(4.22)	(5.00)
Transportation and marketing ($/bbl)	(5.59)	(6.07)
THERMAL OIL OPERATING NETBACK[1] ($/bbl)	$ (2.51)	$ 4.80

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

Thermal Oil Segment Loss

($ Thousands)	Three months ended March 31, 2018	2017
Thermal Oil Operating Income (Loss)[1]	$ (6,744)	$ 10,050
Depletion and depreciation	(21,748)	(14,673)
Acquisition expense	—	(7,647)
Loss on sale of assets	—	(306)
Exploration expenses and other	(304)	(137)
THERMAL OIL SEGMENT LOSS	$ (28,796)	$ (12,713)

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

The increase in depletion and depreciation expense for the three months ended March 31, 2018, compared to the same period in 2017, is primarily due to the Leismer Corner Acquisition on January 31, 2017.

Thermal Oil Capital Expenditures

($ Thousands)	Three months ended March 31, 2018	2017
Leismer Project[1]	$ 11,144	$ 5,332
Hangingstone Project	3,668	5,536
Other Thermal Oil exploration	819	—
TOTAL THERMAL OIL CAPITAL EXPENDITURES[2]	$ 15,631	$ 10,868

(1) 2017 Thermal Oil capital expenditures in the table above exclude the cost of the Leismer Corner Acquisition.
(2) For the three months ended March 31, 2018, capital expenditures include $1.7 million of capitalized staff costs (March 31, 2017 - $0.7 million).

Thermal Oil capital expenditures for the three months ended March 31, 2018 included planned optimization and debottlenecking initiatives at Leismer to maximize production and facility performance, and support future sustaining pad development, as well as downhole pump conversions and replacements.

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 internal funding, an active 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 March 31, 2018, Athabasca had $240.7 million of cash and cash equivalents (including $111.8 million of restricted cash - see page 14). The Company also had available credit of $61.9 million under its $120 million Credit Facility (see below) and additional funding available through the capital-carry receivable from Murphy of $138.4 million (undiscounted).

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)	March 31, 2018	December 31, 2017
2022 Notes[1]	$ 580,545	$ 563,310
Debt issuance costs	(47,081)	(45,039)
Amortization of debt issuance costs	7,996	7,935
TOTAL LONG-TERM DEBT	$ 541,460	$ 526,206

(1) As at March 31, 2018, the US dollar denominated 2022 Notes were translated into Canadian dollars at the period end exchange rate of US$1.00 = C$1.2901.

Athabasca had the following notes and credit facilities in place as at March 31, 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 2017, Athabasca established a $120 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, 2018, 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, 2019. The Credit Facility is subject to a semi-annual borrowing base review with the next review occurring in the latter part of the second quarter of 2018. The Company anticipates extending the Credit Facility at the current $120 million. 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 review, 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 March 31, 2018, the Credit Facility had $58.1 million of letters of credit issued and outstanding related to long-term transportation agreements.

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 March 31, 2018, Athabasca had $107.5 million in letters of credit issued and outstanding under the Letter of Credit Facility, as well as $111.8 million in restricted cash that was primarily related to the Letter of Credit Facility.

Financing and Interest

($ Thousands)	Three months ended March 31, 2018	2017
Financing and interest expense on indebtedness	$ 14,697	$ 14,691
Amortization of debt issuance costs	2,026	5,098
Accretion of provisions	2,857	1,868
TOTAL FINANCING AND INTEREST	$ 19,580	$ 21,657

During the three months ended March 31, 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 Loss, Net

($ Thousands)	Three months ended March 31, 2018	2017
Unrealized foreign exchange loss	$ (15,193)	$ (9,914)
Realized foreign exchange gain (loss)	(219)	32
FOREIGN EXCHANGE LOSS, NET	$ (15,412)	$ (9,882)

In 2017, Athabasca became exposed to foreign currency risk on the principal and interest components of its US dollar denominated 2022 Notes. For the three months ended March 31, 2018 and 2017, the Company recognized a net foreign exchange loss of $15.4 million and $9.9 million, respectively, primarily due to an unrealized loss on the note principal as the average value of the Canadian dollar declined relative to the US dollar in both periods.

Risk Management Contracts

Athabasca maintains an active commodity risk management program designed to support a base level of cash flow and capital spending. The Company currently plans to hedge up to 50% of corporate production volumes for a period of up to one year. 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, subsequent to March 31, 2018, has entered into US dollar forward swap contracts to reduce its exposure to foreign currency risk related to near-term interest payments.

Financial commodity risk management contracts

As at March 31, 2018, Athabasca had the following financial commodity risk management contracts in place:

Instrument	Period	Volume		C$ Average Price/bbl
WTI fixed price swaps	April - June 2018	17,000 bbl/d	$	68.71
WTI/WCS fixed price differential swaps	April - June 2018	14,000 bbl/d	$	(18.62)
WCS fixed price swaps	April - June 2018	2,000 bbl/d	$	51.00
WTI fixed price swaps	July - September 2018	6,000 bbl/d	$	67.69
WTI/WCS fixed price differential swaps	July - September 2018	9,000 bbl/d	$	(18.75)
WTI costless collars	July - September 2018	8,000 bbl/d	$	68.61 - 81.69
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

Additional financial commodity risk management activity related to 2018 has taken place subsequent to March 31, 2018, as noted in the table below:

Instrument	Period	Volume		C$ Average Price/bbl
WTI/WCS fixed price differential swaps	July - September 2018	7,000 bbl/d	$	(24.54)
WTI costless collars	July - September 2018	3,000 bbl/d	$	78.92 - 89.60

The following table summarizes the Company's net gain (loss) on commodity risk management contracts for the three months ended March 31, 2018 and 2017:

	Three months ended March 31,			
($ Thousands)		2018		2017
Unrealized gain (loss) on commodity risk management contracts	$	(3,492)	$	7,214
Realized gain (loss) on commodity risk management contracts		(672)		2,291
GAIN (LOSS) ON COMMODITY RISK MANAGEMENT CONTRACTS (NET)	$	(4,164)	$	9,505

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 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 commodity contracts

Subsequent to March 31, 2018, the following physical commodity contracts were in place:

Instrument	Period	Volume		US$ Average Price/bbl
WTI/WCS fixed price differential contract	April - June 2018	1,382 bbl/d	$	(16.50)
WTI/WCS fixed price differential contract	July - September 2018	1,367 bbl/d	$	(16.50)

Foreign exchange contracts

Subsequent to March 31, 2018, Athabasca entered into US dollar forward swap contracts to reduce its exposure to foreign currency risk on its interest payments associated with the 2022 Notes.

Instrument	Period	Amount (US$ million)	Exchange rate (USD/CAD)
Forward swap contract	August 2018	$ 22,219	$ 1.2544
Forward swap contract	February 2019	$ 22,219	$ 1.2505

Commitments and Contingencies

The following table summarizes Athabasca's estimated future minimum commitments as at March 31, 2018 for the following five years and thereafter:

($ Thousands)	2018	2019	2020	2021	2022	Thereafter	Total
Transportation and processing	$ 77,919	$ 89,952	$ 88,769	$ 150,084	$ 149,911	$ 2,374,881	$ 2,931,516
Repayment of long-term debt(1)	—	—	—	—	580,545	—	580,545
Interest expense on long-term debt(1)	28,664	57,329	57,329	57,329	28,743	—	229,394
Office leases	2,182	2,909	2,909	2,909	2,909	6,058	19,876
Purchase commitments and drilling rigs	1,700	—	—	—	—	—	1,700
TOTAL COMMITMENTS	$ 110,465	$ 150,190	$ 149,007	$ 210,322	$ 762,108	$ 2,380,939	$ 3,763,031

(1) The 2022 Notes and associated interest expense were translated into Canadian dollars at the March 31, 2018 exchange rate of US$1.00 = C$1.2901.

Excluded from the table above is a commitment for $106.1 million for an office lease ending on December 31, 2026 which was re-assigned to an investment-grade third party in December 2013.

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 and 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, 2018	2017
TOTAL GENERAL AND ADMINISTRATIVE	$ 9,034	$ 6,428
G&A per boe	$ 2.47	$ 2.67

During the three months ended March 31, 2018, Athabasca's general and administrative expenses increased compared to the same period in the prior year, primarily due to severance costs and a full quarter of employee costs related to the Leismer Corner Acquisition. However, for the same time period, G&A per boe decreased 7% primarily due to production growth achieved in both the Thermal and Light Oil Divisions. The Company believes it has sufficient resources in place to support planned capital and operating activities over the next several years which is expected to result in further reductions to per unit general and administrative costs.

Gain (loss) on Revaluation of Provisions and Other

($ Thousands)	Three months ended March 31, 2018	2017
Contingent payment obligation	$ (26,265)	$ 6,448
Capital-carry receivable	2,309	3,251
Other	1,743	106
TOTAL GAIN (LOSS) ON REVALUATION OF PROVISIONS AND OTHER	$ (22,213)	$ 9,805

During the three months ended March 31, 2018, Athabasca incurred a $22.2 million loss on revaluation of provisions and other compared to a gain of $9.8 million in the first quarter of 2017. The respective loss and gain are primarily a result of changes in the estimated value of the Company's contingent payment obligation to Statoil 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). Athabasca's estimate of the contingent payment obligation is subject to measurement uncertainty and the difference in the actual cash outflows associated with the obligation could be material.

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 quarter 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 three months ended March 31, 2018, Athabasca issued 0.3 million common shares in respect of the Company's equity-settled share-based compensation plans.

Outstanding Share Data

As at April 30, 2018	
Common shares issued and outstanding	515,046,153
Stock-based compensation plans:	
Stock options	10,785,601
Restricted share units (2010 RSU Plan)	2,071,793
Restricted share units (2015 RSU Plan)	15,001,695
Performance share units	5,426,600
Deferred share units	2,243,470

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)	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	62.87	55.40	48.21	48.29	51.91	49.29	44.94	45.59
WTI (C$/bbl)	79.53	70.47	60.35	64.95	68.52	65.56	58.87	58.81
Western Canadian Select (C$/bbl)	48.77	54.87	47.76	49.99	49.34	46.61	41.01	41.62
Edmonton Par (C$/bbl)	72.06	69.02	56.62	61.92	63.87	61.59	54.66	54.78
Edmonton Condensate (C5+) (C$/bbl)	79.74	73.74	59.01	65.15	68.73	63.38	55.31	56.80
AECO (C$/GJ)	1.97	1.60	1.38	2.64	2.55	2.93	2.20	1.32
NYMEX Henry Hub (US$/MMBtu)	3.00	2.93	3.00	3.19	3.32	2.98	2.81	1.95
Foreign exchange (USD : CAD)	1.27	1.27	1.25	1.34	1.32	1.33	1.31	1.29
CONSOLIDATED								
Volumes (boe/d)	40,572	42,064	36,133	36,574	26,737	11,630	11,848	11,101
Realized price (net of cost of diluent) ($/boe)	22.14	35.30	33.28	32.79	30.63	32.79	28.86	25.87
Revenues ($)(2)	197,280	228,922	181,702	198,247	149,676	54,542	53,210	32,981
Operating Income (Loss) ($)(1)	16,876	65,002	52,358	43,787	19,204	1,433	(577)	(4,700)
Operating Netback ($/boe)(1)	4.65	17.25	15.58	13.28	7.99	1.37	(0.50)	(5.07)
Capital expenditures ($)	82,261	52,418	73,833	45,674	90,124	66,139	22,676	7,705
Capital expenditures net of capital-carry ($)(1)	56,661	33,236	67,741	32,181	79,444	66,087	18,390	6,231
LIGHT OIL DIVISION								
Sales volumes (boe/d)	10,495	11,507	7,875	7,246	3,421	3,337	3,018	5,743
Realized price ($/boe)	36.62	34.22	32.91	36.69	38.97	35.99	29.84	26.93
Revenues ($)(2)	32,675	34,598	21,646	22,956	11,578	10,484	8,086	13,595
Operating Income ($)(1)	24,292	26,696	13,748	16,391	6,863	6,152	5,511	7,215
Operating Netback ($/boe)(1)	25.72	25.22	18.98	24.85	22.28	20.04	19.85	13.80
Capital expenditures ($)	66,630	40,988	53,406	31,061	77,646	62,003	18,920	5,518
Capital expenditures net of capital-carry ($)(1)	41,030	21,806	47,314	17,568	66,966	61,951	14,634	4,044
THERMAL OIL DIVISION								
Bitumen production (bbl/d)	30,077	30,557	28,258	29,328	23,316	8,293	8,830	5,358
Sales volumes (bbl/d)	29,857	29,447	28,640	28,970	23,257	8,015	9,744	4,463
Realized bitumen price ($/bbl)	17.05	35.72	33.38	31.82	29.41	31.46	28.56	24.51
Revenues ($)(2)	164,605	194,324	160,056	175,291	138,098	44,058	45,124	19,386
Operating Income (Loss) ($)(1)	(6,744)	45,385	34,945	26,661	10,050	(4,719)	(6,088)	(11,915)
Operating Netback ($/bbl)(1)	(2.51)	16.75	13.27	10.11	4.80	(6.41)	(6.80)	(29.33)
Capital expenditures ($)	15,631	11,368	20,382	14,127	10,868	4,088	3,754	2,187
OPERATING RESULTS								
Cash Flow from Operating Activities ($)	(3,241)	37,060	49,488	28,049	(52,896)	(19,656)	(18,990)	5,759
Adjusted Funds Flow ($)(1)	(6,360)	41,808	34,400	27,567	(1,649)	(16,867)	(15,778)	(27,304)
Net income (loss) ($)	(93,330)	(209,588)	5,113	24,233	(29,162)	(779,405)	(33,032)	(59,169)
Net income (loss) per share - basic ($)	(0.18)	(0.41)	0.01	0.05	(0.06)	(1.92)	(0.08)	(0.15)
BALANCE SHEET ITEMS								
Cash and cash equivalents ($)	128,915	163,321	174,076	179,611	212,999	650,301	535,477	447,282
Short-term investments ($)	—	—	—	—	—	—	35,000	25,533
Restricted cash ($)	111,778	113,406	113,372	113,853	113,823	107,012	103,827	101,652
Capital-carry receivable (discounted) ($)(3)	132,745	156,036	169,611	173,714	183,745	191,174	188,448	188,742
Total assets ($)	2,318,471	2,323,572	2,498,740	2,488,995	2,524,187	2,257,887	3,017,285	3,028,938
Long-term debt ($)(3)	541,460	526,206	523,782	541,199	553,377	546,209	545,126	544,042
Shareholders' equity ($)	1,434,345	1,524,610	1,731,546	1,723,735	1,695,582	1,557,097	2,333,523	2,363,396

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.
(2) Consists of petroleum and natural gas sales, net of royalties. Excludes interest income.
(3) Balances include the current and long-term portions as reported in the consolidated balance sheets.

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

ACCOUNTING POLICIES AND ESTIMATES

During the three months ended March 31, 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. Under this method, prior years' consolidated financial statements have not been restated. As a result of the adoption of IFRS 15, no cumulative effect adjustment to retained deficit was required and there is 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 months ended March 31, 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. 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. The effective date will be for annual periods beginning on or after January 1, 2019, with earlier adoption permitted. The Company is currently evaluating the impact of adopting IFRS 16 on its consolidated financial statements.

ADVISORIES AND OTHER GUIDANCE

Non-GAAP Financial Measures

The "Adjusted Funds Flow", "Light Oil Operating Income", "Light Oil Operating Netback", "Light Oil Capital Expenditures Net of Capital-Carry", "Thermal Oil Operating Income (Loss)", "Thermal Oil Operating Netback", "Consolidated Operating Income (Loss)", "Consolidated Operating Netback" 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 months ended March 31, 2018 and 2017 to Adjusted Funds Flow:

	Three months ended March 31,	
($ Thousands)	**2018**	**2017**
Cash flow from operating activities	$ (3,241)	$ (52,896)
Acquisition expenses	—	7,647
Changes in non-cash working capital	(6,571)	39,081
Settlement of provisions	3,452	4,519
ADJUSTED FUNDS FLOW	$ (6,360)	$ (1,649)

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 and operating and transportation 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 months ended March 31, 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 and marketing expenses from blended bitumen sales. The Thermal Oil Operating Netback measure is presented on a per barrel basis. The Thermal Oil Operating Income (Loss) and the Thermal Oil Operating Netback measures allow management and others to evaluate the production results from the Company's Thermal Oil assets. The table on page 12 reconciles Thermal Oil Operating Income (Loss) to *Note 17 - Segmented Information* in the consolidated financial statements for the three months ended March 31, 2018.

The Consolidated Operating Income (Loss) and Consolidated Operating Netback measures in this MD&A are calculated by subtracting realized gains/losses on commodity risk management contracts, royalties, the cost of diluent blending, operating expenses and transportation and marketing expenses from petroleum and natural gas sales. The Consolidated Operating Netback measure is presented on a per boe basis. The Consolidated Operating Income (Loss) and the Consolidated Operating Netback measures allow management and others to evaluate the production results from the Company's Light Oil and Thermal Oil assets combined together including the impact of realized commodity risk management gains or losses. The table on page 5 reconciles Consolidated Operating Income (Loss) to *Note 17 - Segmented Information* in the consolidated financial statements for the three months ended March 31, 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 as highlighted 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 first 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 2018 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 project activities related to the Hangingstone Project including 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;
- 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;
- 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;
- 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.

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;
- actions taken by the new 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;
- 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 five-year growth outlook and how that growth outlook is funded; the benefits expected to be realized by the Company from the offering of 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 TMX Pipeline 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 five-year 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 related to the Hangingstone Project; 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 2018 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 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 Canadian and U.S. 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 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 and 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