Management's Discussion and Analysis

December 31, 2017

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 March 7, 2018 and should be read in conjunction with the audited consolidated financial statements of the Company for the years ended December 31, 2017 and 2016. 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 "Forward Looking Information" advisory on page 27 of this MD&A. See "Reserves and Resource Information" on page 28 for important information regarding the Company's reserves and resource information included in this MD&A. For a listing of abbreviations, refer to "Abbreviations" on page 30 of 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 AND YEAR ENDED DECEMBER 31, 2017

Corporate

- Achieved record fourth quarter 2017 production of 42,064 boe/d, an increase of 262% over the prior year. Full year 2017 production averaged 35,421 boe/d, an increase of 196% over the prior year.
- Generated 2017 Adjusted Funds Flow[(1)] of $102.1 million.
- Reduced G&A to $2.26/boe in 2017, a decrease of 62% from the prior year.
- Recapitalized the Company's balance sheet and exited 2017 with $163 million of cash and cash equivalents, a $120 million credit facility and a $164 million (undiscounted) capital carry balance.

Light Oil Division

- Achieved operating scale with record fourth quarter 2017 production of 11,507 boe/d (51% liquids), representing growth of 46% over the third quarter of 2017 and 245% compared to the fourth quarter of 2016. Full year 2017 production averaged 7,535 boe/d (54% liquids), achieving the high end of annual guidance of 6,500 - 7,500 boe/d, and represents an increase of 64% over the prior year.
- 27 (gross) wells placed on production in 2017; 16 (gross) wells at Greater Placid and 11 (gross) wells at Greater Kaybob.
- Realized fourth quarter 2017 operating netbacks[(1)] of $25.22/boe with operating costs of $7.46/boe.
- Generated 2017 operating income[(1)] of $63.7 million, an increase of 168% over the prior year.

Thermal Oil Division

- Successful acquisition and integration of the Leismer oil sands project resulted in record fourth quarter 2017 production of 30,557 bbl/d, an increase of 268% over the prior year. Full year 2017 production averaged 27,886 bbl/d, an increase of 278% over the prior year.
- Realized fourth quarter 2017 operating netbacks[(1)] of $16.75/bbl including $20.60/bbl for Leismer and $8.08/bbl for Hangingstone.
- Generated operating income[(1)] of $117.0 million in 2017, exceeding capital expenditures for the year by $60.3 million.

(1) Refer to "Advisories and Other Guidance" beginning on page 24 for additional information on Non-GAAP Financial Measures.

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 December 31, 2017	Three months ended December 31, 2016	Year ended December 31, 2017	Year ended December 31, 2016
CONSOLIDATED				
Petroleum and natural gas volumes (boe/d)	42,064	11,630	35,421	11,981
Operating Income (Loss)[1][2]	$ 65,002	$ 1,433	$ 180,348	$ (22,012)
Operating Netback[1][2] ($/boe)	$ 17.25	$ 1.37	$ 14.06	$ (5.04)
Capital expenditures[3]	$ 52,418	$ 66,139	$ 262,048	$ 128,079
Capital expenditures net of capital-carry[1][3]	$ 33,236	$ 66,087	$ 212,601	$ 122,267
LIGHT OIL DIVISION				
Petroleum and natural gas volumes (boe/d)	11,507	3,337	7,535	4,597
Operating Income[1]	$ 26,696	$ 6,152	$ 63,697	$ 23,784
Operating Netback[1] ($/boe)	$ 25.22	$ 20.04	$ 23.16	$ 14.13
Capital expenditures	$ 40,988	$ 62,003	$ 203,101	$ 117,090
Capital expenditures net of capital-carry[1]	$ 21,806	$ 61,951	$ 153,654	$ 111,278
THERMAL OIL DIVISION				
Bitumen production (bbl/d)	30,557	8,293	27,886	7,384
Operating Income (Loss)[1]	$ 45,385	$ (4,719)	$ 117,039	$ (45,796)
Operating Netback[1] ($/bbl)	$ 16.75	$ (6.41)	$ 11.62	$ (17.01)
Capital expenditures[3]	$ 11,368	$ 4,088	$ 56,744	$ 10,945
CASH FLOW AND FUNDS FLOW				
Cash flow from operating activities	$ 37,060	$ (19,656)	$ 61,697	$ (70,968)
per share (basic)	$ 0.07	$ (0.05)	$ 0.12	$ (0.17)
Adjusted Funds Flow[1]	$ 41,808	$ (16,867)	$ 102,123	$ (101,502)
per share (basic)	$ 0.08	$ (0.04)	$ 0.20	$ (0.25)
NET LOSS AND COMPREHENSIVE LOSS				
Net loss and comprehensive loss	$ (209,588)	$ (779,405)	$ (209,407)	$ (936,734)
per share (basic and diluted)	$ (0.41)	$ (1.92)	$ (0.42)	$ (2.31)
COMMON SHARES OUTSTANDING				
Weighted average shares outstanding (basic and diluted)	509,901,413	406,406,458	500,136,092	405,621,706

As at ($ Thousands)	December 31, 2017	December 31, 2016
LIQUIDITY AND INDEBTEDNESS		
Cash and cash equivalents	$ 163,321	$ 650,301
Restricted cash	$ 113,406	$ 107,012
Capital-carry receivable (current and long-term portion - undiscounted)	$ 164,023	$ 213,469
Face value of long-term debt (current and long-term portion)[4]	$ 563,310	$ 550,000

(1) Refer to "Advisories and Other Guidance" beginning on page 24 for additional information on Non-GAAP Financial Measures.
(2) Includes realized loss on commodity risk management contracts.
(3) Capital expenditures excludes the cost of the Leismer Corner Acquisition (see page 10).
(4) The face value of the US dollar denominated 2022 Notes as at December 31, 2017 is US$450 million. The 2022 Notes were translated into Canadian dollars at the period end exchange rate of US$1.00 = C$1.2518.

INDEPENDENT RESERVES AND RESOURCES EVALUATION

The Company's qualified independent reserve evaluators, McDaniel & Associates Consultants Ltd. ("McDaniel"), completed independent reserve and resource evaluations effective December 31, 2017. GLJ Petroleum Consultants Ltd. ("GLJ") and DeGoyler and MacNaughton Canada Limited ("D&M"), completed independent reserve and resource evaluations effective December 31, 2016. Athabasca's light oil, natural gas and natural gas liquids reserves are located in the Greater Placid and Greater Kaybob areas within the Company's Light Oil Division. The Company's bitumen reserves and resources are located in the Leismer, Corner, Hangingstone and Dover West areas of the Company's Thermal Oil Division.

Reserves

At December 31, 2017, the Company had 1,246 MMboe of Proved plus Probable Reserves (December 31, 2016 - 264 MMboe). The following table shows the Company's reserves by division:

Reserves	December 31, 2017 Proved	December 31, 2017 Proved plus Probable	December 31, 2016 Proved	December 31, 2016 Proved plus Probable
Light Oil Division				
Greater Placid (MMboe)	39	50	13	23
Greater Kaybob (MMboe)	14	27	7	19
Total Light Oil Division (MMboe)	53	77	20	42
Thermal Oil Division				
Leismer (MMbbl)	304	657	—	—
Corner (MMbbl)	—	331	—	—
Hangingstone (MMbbl)	91	181	92	222
Total Thermal Oil Division (MMbbl)	395	1,169	92	222
Consolidated reserves (MMboe)	448	1,246	112	264

In the Light Oil Division, Proved plus Probable Reserves increased by 83% from 42 MMboe to 77 MMboe for the year ended December 31, 2017. The increase was primarily due to the continued delineation drilling and development activity within Greater Placid and Greater Kaybob.

In the Thermal Oil Division, Proved plus Probable Reserves increased by 427% from 222 MMbbl to 1,169 MMbbl for the year ended December 31, 2017. The increase was primarily due to the addition of reserves acquired in the Leismer Corner Acquisition (as defined on page 10).

Contingent Resources

As at December 31, 2017, Athabasca had 0.3 billion risked barrels (0.3 billion unrisked barrels) of Best Estimate pending Contingent Resources in the Leismer area. In the Corner area, Athabasca had 0.4 billion risked barrels (0.5 billion unrisked barrels) of Best Estimate pending Contingent Resources. In the Dover West Sands area, Athabasca had 1.6 billion risked barrels (2.6 billion unrisked barrels) of Best Estimate on hold Contingent Resources.

Refer to advisories and other guidance starting on page 24, and the Company's AIF dated March 7, 2018, for further details relating to Athabasca's reserves and contingent resources.

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)	~$125
Light Oil (net)	
Production (boe/d)	10,500 - 11,500
Operating Income(1)	~$120
Capital expenditures net of capital-carry(1)	$70
Thermal Oil	
Bitumen production (bbl/d)	28,000 - 29,500
Operating Income(1)	~$100
Capital expenditures	$70
Commodity assumptions	
WTI (US$/bbl)	$60.00
WCS differential (US$/bbl)	$20.00
AECO Gas (C$/Mcf)	$1.50
FX (US$/C$)	0.77

(1) Refer to "Advisories and Other Guidance" beginning on page 24 for additional information on Non-GAAP Financial Measures.

Athabasca's 2018 budget remains unchanged with $140 million in capital expenditures net of capital-carry and corporate production guidance between 38,500 - 41,000 boe/d (87% liquids). The budget will be internally funded with estimated 2018 Adjusted Funds Flow of ~$125 million.

The Company has an active risk management program designed to provide near term balance sheet stability while preserving the Company's upside to improving commodity prices in the medium term. The Company has hedged ~45% of the first half of 2018's dilbit production at ~C$48.50/bbl WCS with targets to hedge up to 50% of 12 month forward production. The Company expects heavy oil differentials to tighten through the second half of 2018 as industry rail activity increases. Longer term, the Company has secured egress for its production to tidewater through the Trans Mountain Pipeline Expansion (the "TMX Pipeline") (20,000 bbl/d) and to the Gulf Coast through the TransCanada Keystone XL Pipeline (the "Keystone XL Pipeline") (10,000 bbl/d). The Company is a net consumer of gas and is a beneficiary of the low Alberta pricing environment.

In Light Oil, Athabasca spud a six (gross) well infill development pad in August 2017 at Greater Placid. The pad was recently completed and is expected to be tied into facilities in March 2018. An additional six (gross) well development pad was spud in late December 2017 and is expected to be rig released in April 2018. The Company maintains operational readiness for completions operations on the six well pad following spring breakup. A robust drilling program is underway at Greater Kaybob with two to three rigs expected to remain active for the balance of 2018. Operations are transitioning to development at Kaybob West with continued delineation drilling at Saxon, Simonette, Kaybob North and Kaybob East. 2018 activity levels have been accelerated with a jointly approved budget of C$387 million (~$30 million net). Operations will now include rig releasing 26 (gross) wells, completion operations on 29 (gross) wells and placing 28 (gross) wells on production.

In Thermal Oil, the Company will continue to optimize capital and operations in order to maximize profitability and long-term recoveries.

Midstream Process

Consistent with the execution of its existing strategy, 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. The Company owns and operates a 300,000 barrel tank farm at Cheecham and dilbit and diluent pipelines between Leismer and Cheecham. The Company intends 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 maintaining a healthy balance sheet, opportunities across its asset base that will generate attractive returns for shareholders, and initiating a share buyback program.

BUSINESS 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 December 31,			Year ended December 31,		
(Average)	2017	2016	Change	2017	2016	Change
Crude oil:						
West Texas Intermediate (WTI) (US$/bbl)(1)	$ 55.40	$ 49.29	12 %	$ 50.93	$ 43.37	17 %
West Texas Intermediate (WTI) (C$/bbl)(1)	$ 70.47	$ 65.56	7 %	$ 66.08	$ 57.25	15 %
Western Canadian Select (WCS) (C$/bbl)(2)	$ 54.87	$ 46.61	18 %	$ 50.50	$ 38.94	30 %
Edmonton Par (C$/bbl)(3)	$ 69.02	$ 61.59	12 %	$ 62.80	$ 52.97	19 %
Edmonton Condensate (C5+) (C$/bbl)(4)	$ 73.74	$ 63.38	16 %	$ 66.45	$ 55.26	20 %
WCS Differential:						
WTI vs. WCS (US$/bbl)	$ (12.20)	$ (14.24)	14 %	$ (12.08)	$ (13.87)	13 %
WTI vs. WCS (C$/bbl)	$ (15.60)	$ (18.95)	18 %	$ (15.58)	$ (18.31)	15 %
Natural gas:						
AECO (C$/GJ)(5)(6)	$ 1.60	$ 2.93	(45)%	$ 2.04	$ 2.05	-
NYMEX Henry Hub (US$/MMBtu)(6)	$ 2.93	$ 2.98	(2)%	$ 3.11	$ 2.46	26 %
Foreign exchange:						
USD : CAD	1.27	1.33	(5)%	1.30	1.32	(2)%

Primary benchmark for:

(1) Crude oil pricing in North America.
(2) Athabasca's blended bitumen sales. WCS trades at a wider differential to the WTI price compared to lighter crude oil products.
(3) Crude oil sales in the Company's Light Oil Division.
(4) Condensate sales in the Company's Light Oil Division and for diluent purchases which Athabasca utilizes in the blending process in the Thermal Oil Division.
(5) Natural gas consumed by Athabasca in order to generate steam in the Thermal Oil Division.
(6) Natural gas sales in the Company's Light Oil Division.

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 the commodity risk management losses see the Risk Management Contracts section within this MD&A.

Consolidated Operating Results

	Three months ended December 31, 2017	Three months ended December 31, 2016	Year ended December 31, 2017	Year ended December 31, 2016
VOLUMES				
Oil and condensate (bbl/d)	4,809	1,542	3,549	1,904
Natural gas (Mcf/d)	33,905	9,260	20,890	13,858
Natural gas liquids (bbl/d)	1,047	252	505	383
Bitumen production (bbl/d)	30,557	8,293	27,886	7,384
Total (boe/d)	42,064	11,630	35,421	11,981

($ Thousands, unless otherwise noted)	Three months ended December 31, 2017	Three months ended December 31, 2016	Year ended December 31, 2017	Year ended December 31, 2016
Petroleum and natural gas sales	$ 232,606	$ 55,381	$ 770,172	$ 176,110
Realized loss on commodity risk mgmt contracts	(7,079)	—	(388)	—
Royalties	(3,684)	(839)	(11,625)	(2,357)
Cost of diluent	(99,611)	(21,131)	(343,742)	(66,706)
Operating expenses	(43,013)	(23,663)	(175,661)	(94,490)
Transportation and marketing	(14,217)	(8,315)	(58,408)	(34,569)
Consolidated Operating Income (Loss)[(1)]	$ 65,002	$ 1,433	$ 180,348	$ (22,012)
REALIZED PRICES				
Oil and condensate ($/bbl)	$ 66.53	$ 57.08	$ 59.62	$ 47.07
Natural gas ($/Mcf)	0.72	2.88	1.63	2.03
Natural gas liquids ($/bbl)	47.05	21.38	35.82	20.03
Blended bitumen sales ($/bbl)	50.99	43.09	47.38	34.67
Realized price (net of cost of diluent) ($/boe)	35.30	32.79	33.25	25.00
Realized loss on commodity risk mgmt contracts ($/boe)	(1.88)	—	(0.03)	—
Royalties ($/boe)	(0.98)	(0.80)	(0.91)	(0.54)
Operating expenses ($/boe)	(11.42)	(22.66)	(13.70)	(21.60)
Transportation and marketing ($/boe)	(3.77)	(7.96)	(4.55)	(7.90)
CONSOLIDATED OPERATING NETBACK[(1)] ($/boe)	$ 17.25	$ 1.37	$ 14.06	$ (5.04)

(1) Refer to "Advisories and Other Guidance" beginning on page 24 for additional information on Non-GAAP Financial Measures.

Consolidated Segments Loss

($ Thousands)	Three months ended December 31, 2017	Three months ended December 31, 2016	Year ended December 31, 2017	Year ended December 31, 2016
Consolidated Operating Income (Loss)[(1)]	$ 65,002	$ 1,433	$ 180,348	$ (22,012)
Unrealized loss on commodity risk management contracts	(5,836)	—	(3,548)	—
Impairment loss	(189,535)	(751,585)	(189,535)	(751,585)
Depletion and depreciation	(38,475)	(12,932)	(113,697)	(59,069)
Acquisition expense	—	—	(11,047)	—
Gain (loss) on sale of assets	515	3,200	143	(4,471)
Exploration expense and other	(14)	(28)	(320)	(287)
CONSOLIDATED SEGMENTS LOSS	$ (168,343)	$ (759,912)	$ (137,656)	$ (837,424)

(1) Refer to "Advisories and Other Guidance" beginning on page 24 for additional information on Non-GAAP Financial Measures.

Consolidated Capital Expenditures

($ Thousands)	Three months ended December 31, 2017	Three months ended December 31, 2016	Year ended December 31, 2017	Year ended December 31, 2016
Light Oil Division	$ 40,988	$ 62,003	$ 203,101	$ 117,090
Thermal Oil Division(1)	11,368	4,088	56,744	10,945
Corporate assets	62	48	2,203	44
TOTAL CAPITAL EXPENDITURES(2)	$ 52,418	$ 66,139	$ 262,048	$ 128,079
Less: Greater Kaybob capital-carry	(19,182)	(52)	(49,447)	(5,812)
TOTAL CAPITAL EXPENDITURES NET OF CAPITAL-CARRY(3)	$ 33,236	$ 66,087	$ 212,601	$ 122,267

(1) Thermal Oil capital expenditures in the table above exclude the cost of the Leismer Corner Acquisition (as defined on page 10).
(2) For the three months and year ended December 31, 2017, capital expenditures include $3.2 million and $12.6 million of capitalized staff costs, respectively (December 31, 2016 - $1.9 million, $7.8 million).
(3) Refer to "Advisories and Other Guidance" beginning on page 24 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.

On May 13, 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"). As part of the transaction, Athabasca sold an operated 70% interest in its Greater Kaybob assets and a non-operated 30% interest in its Greater Placid assets for gross proceeds of $486.5 million. Athabasca received $267.5 million in cash, including purchase price adjustments from the January 1, 2016 effective date, and also recognized consideration of $219.0 million (undiscounted) in the form of a capital-carry in Greater Kaybob, whereby Murphy committed to funding 75% of Athabasca's share of development capital 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.

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. During the year ended December 31, 2017, the Light Oil Division produced 7,535 boe/d and as at December 31, 2017 had approximately 77 MMboe of Proved plus Probable Reserves[2].

(1) Refer to "Advisories and Other Guidance" beginning on page 24 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 page 28 and the AIF for additional information about the Company's Reserves and Contingent Resources.

Light Oil Operating Results

	Three months ended December 31, 2017	Three months ended December 31, 2016	Year ended December 31, 2017	Year ended December 31, 2016
SALES VOLUMES				
Oil and condensate (bbl/d)	4,809	1,542	3,549	1,904
Natural gas (Mcf/d)	33,905	9,260	20,890	13,858
Natural gas liquids (bbl/d)	1,047	252	505	383
Total (boe/d)	11,507	3,337	7,535	4,597
Consisting of:				
Greater Placid area (boe/d)	9,556	1,836	5,906	1,827
% liquids	48%	53%	52%	50%
Greater Kaybob area (boe/d)	1,951	1,501	1,629	2,770
% liquids	63%	54%	61%	50%

($ Thousands, unless otherwise noted)	Three months ended December 31, 2017	Three months ended December 31, 2016	Year ended December 31, 2017	Year ended December 31, 2016
Petroleum and natural gas sales	$ 36,227	$ 11,049	$ 96,261	$ 45,899
Royalties	(1,629)	(565)	(5,483)	(1,792)
Operating and transportation expenses	(7,902)	(4,332)	(27,081)	(20,323)
Light Oil Operating Income(1)	$ 26,696	$ 6,152	$ 63,697	$ 23,784
REALIZED PRICES				
Oil and condensate ($/bbl)	$ 66.53	$ 57.08	$ 59.62	$ 47.07
Natural gas ($/Mcf)	0.72	2.88	1.63	2.03
Natural gas liquids ($/bbl)	47.05	21.38	35.82	20.03
Realized price ($/boe)	34.22	35.99	35.00	27.28
Royalties ($/boe)	(1.54)	(1.84)	(1.99)	(1.07)
Operating and transportation expenses ($/boe)	(7.46)	(14.11)	(9.85)	(12.08)
LIGHT OIL OPERATING NETBACK(1) ($/boe)	$ 25.22	$ 20.04	$ 23.16	$ 14.13

(1) Refer to "Advisories and Other Guidance" beginning on page 24 for additional information on Non-GAAP Financial Measures.

Athabasca's Light Oil production averaged 11,507 boe/d during the fourth quarter of 2017, an increase of 245% compared to the fourth quarter of 2016. During the year ended December 31, 2017, Light Oil production averaged 7,535 boe/d, an increase of 64% compared to the prior year. Production growth in 2017 was primarily a result of the tie-in of 16 (gross) Montney and 11 (gross) Duvernay wells, which more than offset production sold in 2016 as part of the Murphy Transaction.

Athabasca's Light Oil Operating Netback was $25.22/boe in the fourth quarter of 2017, a 26% increase from the prior year fourth quarter. The increase was primarily due to higher liquids prices and lower per boe operating costs, partially offset by lower realized gas prices. Athabasca's 2017 Light Oil Operating Netback was $23.16/boe, a 64% increase from the prior year, primarily due to higher liquids content and liquid prices and lower per boe operating expenses. Light Oil operating and transportation expenses trended down significantly in 2017, averaging $7.46/boe in the fourth quarter, with significantly higher production volumes driving economies of scale over fixed costs.

As a result of higher production and higher netbacks, Athabasca generated Light Oil operating income of $63.7 million in 2017, a 168% increase over 2016.

Light Oil Segment Income (Loss)

($ Thousands)	Three months ended December 31, 2017	2016	Year ended December 31, 2017	2016
Light Oil Operating Income[1]	$ 26,696	$ 6,152	$ 63,697	$ 23,784
Depletion and depreciation	(15,721)	(4,156)	(40,515)	(30,212)
Gain (loss) on sale of assets	530	3,200	429	(4,471)
Exploration expense and other	(9)	(30)	(86)	(54)
LIGHT OIL SEGMENT INCOME (LOSS)	$ 11,496	$ 5,166	$ 23,525	$ (10,953)

(1) Refer to "Advisories and Other Guidance" beginning on page 24 for additional information on Non-GAAP Financial Measures.

Depletion and depreciation of oil and gas assets increased $11.6 million in the fourth quarter of 2017 and $10.3 million for the full year 2017, compared to the same periods in prior year, mostly due to higher production volumes.

Light Oil Capital Expenditures

($ Thousands)	Three months ended December 31, 2017	2016	Year ended December 31, 2017	2016
Greater Placid				
Drilling, completion and equipping	$ 12,003	$ 52,571	$ 100,387	$ 88,650
Facilities	4,300	614	33,111	7,427
Land acquisitions and other	2,088	5,851	7,701	6,903
	18,391	59,036	141,199	102,980
Greater Kaybob				
Drilling, completion and equipping	21,784	3,287	59,610	13,731
Facilities	636	(200)	1,735	307
Land acquisitions and other	177	(120)	557	72
	22,597	2,967	61,902	14,110
TOTAL LIGHT OIL CAPITAL EXPENDITURES[1]	$ 40,988	$ 62,003	$ 203,101	$ 117,090
Less: Greater Kaybob capital carry	(19,182)	(52)	(49,447)	(5,812)
TOTAL CAPITAL EXPENDITURES NET OF CAPITAL-CARRY[2]	$ 21,806	$ 61,951	$ 153,654	$ 111,278

(1) For the three months and year ended December 31, 2017, capital expenditures include $1.6 million and $6.0 million of capitalized staff costs, respectively (December 31, 2016 - $1.5 million, $6.0 million).
(2) Refer to "Advisories and Other Guidance" beginning on page 24 for additional information on Non-GAAP Financial Measures.

In 2017, Athabasca completed its 2016/17 20 (gross) well winter drilling program in Greater Placid with 16 (gross) wells brought on production during the year. The Company also commenced its 2017/18 winter drilling program in the third quarter of 2017 spudding a six (gross) well pad which was rig released in the fourth quarter and is expected to be on-stream in the first half of 2018. A second six (gross) well pad was spud in the fourth quarter of 2017 and is expected to be rig-released prior to spring break-up. During 2017, Athabasca also commissioned its Placid battery in the second quarter, with a third compressor added in the fourth quarter to accommodate production growth in the area.

In Greater Kaybob, a total of 13 (gross) Duvernay wells were rig released and 11 (gross) Duvernay wells were brought on production in 2017. An additional 10 (gross) Duvernay wells were spud in the fourth quarter of 2017, and are expected to be on-stream in 2018. Including recovery of the capital-carry, Athabasca's net cash outflow from capital expenditures in Greater Kaybob was $12.5 million during the year ended December 31, 2017.

During the first half of 2016, in Greater Placid Athabasca completed three, and brought on stream four (gross), Montney wells that had been drilled in the prior year. In the second half of 2016, Athabasca commenced its 2016/17 20 (gross) well winter drilling program. Athabasca also spent $8.3 million net of capital carry in Greater Kaybob in 2016 primarily to complete and bring on stream a four (gross) well Duvernay pad.

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 an 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. This high quality asset increases the scale of Athabasca's Thermal Oil division, improves resiliency to lower commodity prices and has resulted in higher year-over-year Thermal Oil netbacks and operating income. 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 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, including $0.9 million in purchase price adjustments, and the issuance of 100 million common shares which were valued at $166.0 million based on Athabasca's January 31, 2017 closing share price of $1.66/share. 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 payable by Athabasca in respect of the contingent payment obligation during the year ended December 31, 2017. Athabasca incurred $11.0 million in acquisition costs associated with the Leismer Corner Acquisition.

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 legacy 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.

(1) Based on the report of Athabasca's independent reserve evaluator effective December 31, 2017. Refer to page 28 and the AIF for additional information about the Company's Reserves and Contingent Resources.

Leismer Operating Results

	Three months ended December 31, 2017	Eleven months ended December 31, 2017	Year ended December 31, 2017
VOLUMES			
Bitumen production (bbl/d)	20,991	20,706	18,948
Bitumen sales (bbl/d)	20,408	20,518	18,776
Blended bitumen sales (bbl/d)	29,037	29,028	26,563

($ Thousands, unless otherwise noted)	Three months ended, December 31 2017	Year ended December 31, 2017
Blended bitumen sales	$ 136,026	$ 460,033
Cost of diluent	(70,139)	(236,348)
Total bitumen sales	65,887	223,685
Royalties	(1,446)	(4,323)
Operating expenses - non-energy	(15,232)	(60,611)
Operating expenses - energy	(5,564)	(23,245)
Transportation and marketing	(4,983)	(19,088)
Leismer Operating Income(1)(2)	$ 38,662	$ 116,418
REALIZED PRICE		
Blended bitumen sales ($/bbl)	$ 50.92	$ 47.45
Bitumen sales ($/bbl)	$ 35.09	$ 32.64
Royalties ($/bbl)	(0.77)	(0.63)
Operating expenses - non-energy ($/bbl)	(8.11)	(8.84)
Operating expenses - energy ($/bbl)	(2.96)	(3.39)
Transportation and marketing ($/bbl)	(2.65)	(2.79)
LEISMER OPERATING NETBACK(1)(2) ($/bbl)	$ 20.60	$ 16.99

(1) Refer to "Advisories and Other Guidance" beginning on page 24 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 onwards for the year ended December 31, 2017.

In the fourth quarter of 2017, Leismer averaged production of 20,991 bbl/d with stable well and facility operations resulting in increased production volumes relative to the third quarter. From the date of closing the Leismer Corner Acquisition to the end of December 2017 Leismer has averaged production of 20,706 bbl/d.

During the fourth quarter of 2017, the Leismer Operating Netback was $20.60/bbl, which represents an improvement of 16% over the third quarter of 2017. The increase was primarily a result of increased realized pricing for blended bitumen sales partially offset by higher blending rates to meet winter pipeline specifications. For the year ended December 31, 2017, Leismer generated an operating netback of $16.99/bbl and operating income of $116.4 million.

The Company continues to optimize capital and operating expenses to maximize profitability of the Leismer Project.

Hangingstone Operating Results

	Three months ended December 31, 2017	2016	Year ended December 31, 2017	2016
VOLUMES				
Bitumen production (bbl/d)	9,566	8,293	8,938	7,384
Bitumen sales (bbl/d)	9,039	8,015	8,822	7,358
Blended bitumen sales (bbl/d)	12,827	11,184	12,402	10,262

($ Thousands, unless otherwise noted)	Three months ended December 31, 2017	2016	Year ended December 31, 2017	2016
Blended bitumen sales	$ 60,353	$ 44,332	$ 213,878	$ 130,211
Cost of diluent	(29,472)	(21,131)	(107,394)	(66,706)
Total bitumen sales	30,881	23,201	106,484	63,505
Royalties	(609)	(274)	(1,819)	(565)
Operating expenses - non-energy	(10,079)	(13,315)	(46,473)	(57,161)
Operating expenses - energy	(4,406)	(6,171)	(19,763)	(17,297)
Transportation and marketing	(9,064)	(8,160)	(37,808)	(34,278)
Hangingstone Operating Income (Loss)[1]	$ 6,723	$ (4,719)	$ 621	$ (45,796)
REALIZED PRICE				
Blended bitumen sales ($/bbl)	$ 51.14	$ 43.09	$ 47.25	$ 34.67
Bitumen sales ($/bbl)	$ 37.13	$ 31.46	$ 33.07	$ 23.58
Royalties ($/bbl)	(0.73)	(0.37)	(0.56)	(0.21)
Operating expenses - non-energy ($/bbl)	(12.12)	(18.06)	(14.43)	(21.23)
Operating expenses - energy ($/bbl)	(5.30)	(8.37)	(6.14)	(6.42)
Transportation and marketing ($/bbl)	(10.90)	(11.07)	(11.74)	(12.73)
HANGINGSTONE OPERATING NETBACK[1] ($/bbl)	$ 8.08	$ (6.41)	$ 0.20	$ (17.01)

(1) Refer to “Advisories and Other Guidance” beginning on page 24 for additional information on Non-GAAP Financial Measures.

For the three months ended December 31, 2017, Hangingstone averaged 9,566 bbl/d of bitumen production, an increase of 15% compared to the same period in the prior year with stable operations in the fourth quarter of 2017 increasing overall production volumes. For the year ended December 31, 2017, Hangingstone averaged 8,938 bbl/d of bitumen production, an increase of 21% compared to the prior year due to continued steam chamber development.

The Hangingstone Operating Netback was $8.08/bbl in the fourth quarter of 2017 compared to $(6.41)/bbl during the same period in 2016 and $0.20/bbl for the year ended December 31, 2017 compared to $(17.01)/bbl in 2016. The improvement in the Hangingstone Operating Netback is primarily due to higher production volumes, higher pricing and lower operating expenses.

Compared to the prior year periods, the fourth quarter of 2017 operating expenses per bbl decreased by 34% to $17.42/bbl and for the full year 2017 decreased by 26% to $20.57/bbl. The decreases are primarily due to lower non-energy operating expenses combined with higher production.

As a result of higher production and positive netbacks, Hangingstone generated operating income of $6.7 million in the fourth quarter of 2017 compared to an operating loss of $4.7 million during the same period in 2016 and operating income of $0.6 million for the year ended December 31, 2017 compared to an operating loss of $45.8 million in 2016.

In the second quarter of 2016, Hangingstone bitumen production was impacted by a 19 day shutdown as a result of the regional Fort McMurray wildfires. In the second quarter of 2017, Athabasca recognized $8.0 million of insurance proceeds in Other Income with respect to the settlement of an insurance claim filed to recover certain losses associated with the shutdown.

Consolidated Thermal Oil Operating Results

	Three months ended December 31, 2017	Three months ended December 31, 2016	Year ended December 31, 2017	Year ended December 31, 2016
VOLUMES				
Bitumen production (bbl/d)	30,557	8,293	27,886	7,384
Bitumen sales (bbl/d)	29,447	8,015	27,598	7,358
Blended bitumen sales (bbl/d)	41,864	11,184	38,965	10,262

($ Thousands, unless otherwise noted)	Three months ended December 31, 2017	Three months ended December 31, 2016	Year ended December 31, 2017	Year ended December 31, 2016
Blended bitumen sales	$ 196,379	$ 44,332	$ 673,911	$ 130,211
Cost of diluent	(99,611)	(21,131)	(343,742)	(66,706)
Total bitumen sales	96,768	23,201	330,169	63,505
Royalties	(2,055)	(274)	(6,142)	(565)
Operating expenses - non-energy	(25,311)	(13,315)	(107,084)	(57,161)
Operating expenses - energy	(9,970)	(6,171)	(43,008)	(17,297)
Transportation and marketing	(14,047)	(8,160)	(56,896)	(34,278)
Thermal Oil Operating Income (Loss)(1)	$ 45,385	$ (4,719)	$ 117,039	$ (45,796)
REALIZED PRICE				
Blended bitumen sales ($/bbl)	$ 50.99	$ 43.09	$ 47.38	$ 34.67
Bitumen sales ($/bbl)	$ 35.72	$ 31.46	$ 32.78	$ 23.58
Royalties ($/bbl)	(0.76)	(0.37)	(0.61)	(0.21)
Operating expenses - non-energy ($/bbl)	(9.34)	(18.06)	(10.63)	(21.23)
Operating expenses - energy ($/bbl)	(3.68)	(8.37)	(4.27)	(6.42)
Transportation and marketing ($/bbl)	(5.19)	(11.07)	(5.65)	(12.73)
THERMAL OIL OPERATING NETBACK(1) ($/bbl)	$ 16.75	$ (6.41)	$ 11.62	$ (17.01)

(1) Refer to “Advisories and Other Guidance” beginning on page 24 for additional information on Non-GAAP Financial Measures.

Thermal Oil Segment Loss

($ Thousands)	Three months ended December 31, 2017	Three months ended December 31, 2016	Year ended December 31, 2017	Year ended December 31, 2016
Thermal Oil Operating Income (Loss)(1)	$ 45,385	$ (4,719)	$ 117,039	$ (45,796)
Impairment loss	(189,535)	(751,585)	(189,535)	(751,585)
Depletion and depreciation	(22,754)	(8,776)	(73,182)	(28,857)
Acquisition expense	—	—	(11,047)	—
Loss on sale of assets	(15)	—	(286)	—
Exploration expenses and other	(5)	2	(234)	(233)
THERMAL OIL SEGMENT LOSS	$ (166,924)	$ (765,078)	$ (157,245)	$ (826,471)

(1) Refer to “Advisories and Other Guidance” beginning on page 24 for additional information on Non-GAAP Financial Measures.

In the fourth quarter of 2017, Athabasca recognized an impairment loss of $189.5 million related to its Hangingstone and Birch assets as a result of revised estimates around recoverable reserves and/or contingent resources and future development timing associated with each property. In the fourth quarter of 2016, Athabasca recognized an impairment loss of $751.6 million related to Hangingstone.

The increase in depletion and depreciation expense for the three months and year ended December 31, 2017, compared to the same periods in 2016, is primarily due to the Leismer Corner Acquisition.

Thermal Oil Capital Expenditures

($ Thousands)	Three months ended December 31, 2017	2016	Year ended December 31, 2017	2016
Leismer Project[1]	$ 9,544	$ —	$ 35,920	$ —
Hangingstone Project	252	3,384	16,780	7,821
Other Thermal Oil exploration	1,572	704	4,044	3,124
TOTAL THERMAL OIL CAPITAL EXPENDITURES[2]	$ 11,368	$ 4,088	$ 56,744	$ 10,945

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

(2) For the three months and year ended December 31, 2017, capital expenditures include $1.6 million and $6.6 million of capitalized staff costs, respectively (December 31, 2016 - $0.4 million, $1.8 million).

In response to lower commodity prices in 2017, the Company significantly reduced its Thermal Oil capital activity with spending reduced by 46% compared to its initial 2017 budget of $105 million. Capital expenditures for the year ended December 31, 2017 were primarily related to downhole pump conversions and replacements, work performed on previously drilled infill wells and the installation of flow control devices at Leismer, and an enhanced diluent recovery project at Hangingstone.

Sale of Contingent Bitumen Royalty to Burgess

During the year ended December 31, 2016, Athabasca granted a Contingent Bitumen Royalty (the "Royalty") on its legacy Thermal Oil assets to Burgess Energy Holdings L.L.C. ("Burgess") for gross cash proceeds of $307.0 million. Under the terms of the Royalty, Athabasca will pay Burgess a linear-scale Royalty of 0% - 12%, relative to a WCS benchmark price, applied to Athabasca's realized bitumen price (C$), which is determined net of diluent, transportation and storage costs.

On February 24, 2017, Athabasca granted an additional Royalty under the same terms to Burgess on its newly acquired Leismer and Corner assets for additional cash proceeds of $90.0 million, bringing the total gross proceeds received by the Company from the sale of the Royalty to $397.0 million.

The Royalty has been structured so that the assets will not be encumbered at lower pricing levels nor is it expected to materially impact the economics of future Leismer or Hangingstone expansion phases or other future Thermal Oil exploration projects. The Royalty has no associated commitments to develop future expansions or projects and Burgess has the option of either receiving the Royalty in cash or in kind.

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[1]	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[1]	2% - 12%
$150/bbl and above	12%

(1) The WCS benchmark price is used to determine the linear sliding-scale royalty rate.

During the years ended December 31, 2017 and 2016, no amounts were payable in respect of the Royalty to Burgess.

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 cash flow from operating activities, 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 December 31, 2017, Athabasca had $276.7 million of cash and cash equivalents (including $113.4 million of restricted cash - see page 16). The Company also had available credit of $61.9 million under its $120 million New Credit Facility (see below) and additional funding available through the capital-carry receivable from Murphy of $164.0 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)	December 31, 2017	December 31, 2016
2022 Notes[(1)]	$ 563,310	$ —
2017 Notes	—	550,000
Debt issuance costs[(1)]	(45,039)	(21,664)
Amortization of debt issuance costs	7,935	17,873
TOTAL LONG-TERM DEBT	$ 526,206	$ 546,209

(1) As at December 31, 2017, the US dollar denominated 2022 Notes and associated debt issuance costs were translated into Canadian dollars at the period end exchange rate of US$1.00 = C$1.2518.

In 2016 and early 2017, Athabasca recapitalized its balance sheet through a series of refinancing transactions which included:

- the repayment of the Company's US$225 million senior secured first lien term loan (the "Term Loan") in the second quarter of 2016;
- the issuance of US$450.0 million (C$589.0 million) of senior secured second lien notes on February 24, 2017 (the "2022 Notes"), with the proceeds used to retire the Company's existing C$550.0 million of senior secured second lien notes which were due in November 2017 (the "2017 Notes"); and,
- the establishment of a new $120 million reserve-based credit facility (the "New Credit Facility").

This refinancing provided Athabasca with a multi-year funding platform and strong liquidity outlook which will allow the Company to advance its strategic objectives and maintain business flexibility.

2022 Notes

The 2022 Notes bear interest at a rate of 9.875% per annum, payable semi-annually, and have a term of five years maturing 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

New Credit Facility

The New Credit Facility, which was reaffirmed by the lenders on November 30, 2017, is a $120 million, 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 New Credit Facility is subject to a semi-annual borrowing base review with the next review occurring in the second quarter of 2018. The borrowing base of the New Credit Facility will be 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.

Amounts borrowed under the New 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 3.50% to 4.50%. The Company incurs an issuance fee for letters of credit of 4.50% and a standby fee on the undrawn portion of the New Credit Facility of 1.125%. As at December 31, 2017, the New 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%. Letters of credit issued under the Letter of Credit Facility are primarily used to satisfy financial assurance requirements under Athabasca's long-term transportation agreements. 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 December 31, 2017, Athabasca had $109.1 million in letters of credit issued under the Letter of Credit Facility, as well as $113.4 million in restricted cash that was primarily related to the Letter of Credit Facility.

Financing and Interest

	Three months ended December 31,		Year ended December 31,	
($ Thousands)	2017	2016	2017	2016
Financing and interest expense on indebtedness	$ 15,051	$ 10,572	$ 60,411	$ 56,223
Amortization of debt issuance costs	2,489	1,345	12,639	13,129
Accretion of provisions	2,772	1,841	9,757	7,543
TOTAL FINANCING AND INTEREST	$ 20,312	$ 13,758	$ 82,807	$ 76,895

During the three months and year ended December 31, 2017, financing and interest expenses were primarily attributable to the Company's 2022 Notes. Athabasca also incurred fees related to its New Credit Facility and Letter of Credit Facility.

During the three months and year ended December 31, 2016, financing and interest expenses were primarily attributable to Athabasca's 2017 Notes. Athabasca also incurred standby fees and fees on issued letters of credit.

Foreign Exchange Gain (Loss), Net

	Three months ended December 31,		Year ended December 31,	
($ Thousands)	2017	2016	2017	2016
Unrealized foreign exchange gain (loss)	$ (298)	$ —	$ 23,653	$ —
Realized foreign exchange gain (loss)	(7)	(6)	471	19,875
FOREIGN EXCHANGE GAIN (LOSS), NET	$ (305)	$ (6)	$ 24,124	$ 19,875

During the first quarter of 2017, Athabasca became exposed to foreign currency risk on the principal and interest components of its newly issued US dollar denominated 2022 Notes. For the year ended December 31, 2017, the Company recognized a net foreign exchange gain of $24.1 million primarily due to an unrealized gain on the note principal as the average value of the Canadian dollar improved relative to the US dollar from the date the notes were issued to the end of the year from 1.31:1 to 1.25:1.

During the year ended December 31, 2016, Athabasca was exposed to foreign currency risk on the principal and interest components of it US dollar denominated Term Loan and recognized a net foreign exchange gain of $19.9 million primarily due to a realized gain on the loan principal as the average value of the Canadian dollar increased relative to the US dollar from 1.38:1 to 1.29:1 from the beginning of the year until the date of the repayment of the Term Loan.

Risk Management Contracts

In 2017, Athabasca commenced an active commodity risk management program designed to support a base level of cash flow and capital spending. The Company currently intends to hedge up to 50% of corporate production volumes for a period of up to one year.

As at December 31, 2017, Athabasca has the following risk management contracts in place:

Instrument	Period	Volume		C$ Average Price/bbl
WTI/WCS differential fixed price swaps	January - March 2018	8,000 bbl/d	$	(17.82)
WCS fixed price swaps	January - March 2018	10,000 bbl/d	$	48.60
WTI fixed price swaps	January - March 2018	11,000 bbl/d	$	66.15
WTI/WCS differential fixed price swaps	April - June 2018	9,000 bbl/d	$	(18.88)
WCS fixed price swaps	April - June 2018	4,000 bbl/d	$	49.53
WTI fixed price swaps	April - June 2018	12,000 bbl/d	$	67.14
WTI/WCS differential fixed price swaps	July - September 2018	3,000 bbl/d	$	(19.27)
WCS fixed price swaps	July - September 2018	3,000 bbl/d	$	48.87
WTI fixed price swaps	July - September 2018	3,000 bbl/d	$	67.27
WTI/WCS differential fixed price swaps	January - December 2018	3,000 bbl/d	$	(17.72)

Additional commodity risk management activity related to 2018 has taken place subsequent to December 31, 2017, as noted in the table below:

Instrument	Period	Volume		C$ Average Price/bbl
WTI fixed price swaps	April - June 2018	3,000 bbl/d	$	76.25
WTI costless collars	July - September 2018	7,000 bbl/d	$	68.48 - 81.71
WTI costless collars	July - December 2018	1,000 bbl/d	$	69.50 - 81.50

The following table summarizes the Company's net loss on risk management contracts for the three months and years ended December 31, 2017 and 2016:

	Three months ended December 31,				Year ended December 31,			
($ Thousands)		2017		2016		2017		2016
COMMODITY CONTRACTS								
Unrealized loss on commodity risk management contracts	$	(5,836)	$	—	$	(3,548)	$	—
Realized loss on commodity risk management contracts		(7,079)		—		(388)		—
FOREIGN EXCHANGE CONTRACTS								
Realized loss on foreign exchange risk management contracts		—		—		—		(21,628)
LOSS ON RISK MANAGEMENT CONTRACTS (NET)	$	(12,915)	$	—	$	(3,936)	$	(21,628)

The commodity risk management contracts for the three months and year ended December 31, 2017 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), respectively. As the commodity derivatives are unwound (i.e. settled in cash), Athabasca recognizes a corresponding realized gain or loss in net income (loss).

During the year ended December 31, 2016, Athabasca recognized a loss on risk management contracts of $21.6 million related to a foreign currency derivative put in place with respect to the Company's US dollar denominated Term Loan.

Commitments and Contingencies

The following table summarizes Athabasca's estimated future minimum commitments as at December 31, 2017 for the following five years and thereafter:

($ Thousands)	2018	2019	2020	2021	2022	Thereafter	Total
Transportation	$ 106,061	$ 89,952	$ 88,769	$ 149,288	$ 149,116	$ 2,360,557	$ 2,943,743
Repayment of long-term debt[1]	—	—	—	—	563,310	—	563,310
Interest expense on long-term debt[1]	55,627	55,627	55,627	55,627	27,889	—	250,397
Office leases	2,909	2,909	2,909	2,909	2,909	6,058	20,603
Purchase commitments and drilling rigs	2,229	—	—	—	—	—	2,229
TOTAL COMMITMENTS	$ 166,826	$ 148,488	$ 147,305	$ 207,824	$ 743,224	$ 2,366,615	$ 3,780,282

(1) The 2022 Notes and associated interest expense were translated into Canadian dollars at the December 31, 2017 exchange rate of US$1.00 = C$1.2518.

During the first quarter of 2017, Athabasca acquired firm service on the TMX Pipeline by entering into a long-term transportation service agreement with Trans Mountain Pipeline L.P. to deliver up to 20,000 bbl/d of the Company's blended bitumen from Edmonton, Alberta to Burnaby, B.C., estimated to start in early 2021.

In conjunction with the Leismer Corner Acquisition, Statoil reassigned to Athabasca its existing commitment for the transportation of blended bitumen on the Enbridge Waupisoo pipeline. During the third quarter of 2017, Athabasca entered into a new long-term transportation agreement with Enbridge Pipelines (Athabasca) Inc. for the delivery of up to 33,000 bbl/d of blended bitumen which replaced the previous Waupisoo commitment. The new agreement was effective July 1, 2017.

A second transportation commitment was reassigned by Statoil to Athabasca for the transportation of diluent to the Leismer Project's central processing facility.

During the fourth quarter of 2017, Athabasca entered into a dilbit transportation services agreement for 10,000 bbl/d on the Keystone XL Pipeline for 20 years, estimated to start in early 2021. Athabasca also entered into a firm service transportation agreement for 9,000 bbl/d of diluent on the Enbridge and Keyera Partnership-owned Norlite pipeline from Edmonton, Alberta to Athabasca's Cheecham facility, effective May 2018.

In the Light Oil Division, Athabasca entered into two gas handling agreements during the fourth quarter of 2017. The first agreement is with Keyera Corp. for an initial 28 MMcf/d of gas, effective in the first quarter of 2018. The second agreement with SemCAMS is for an initial 6 MMcf/d of gas delivered to the Smoke Lake Plant, effective in the fourth quarter of 2019.

Excluded from the table above is a commitment for $109.0 million for an office lease ending on December 31, 2026 which was 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.

Credit Risk

The maximum exposure to credit risk is currently represented by the carrying amounts of cash and cash equivalents, restricted cash, accounts receivable, the capital-carry receivable and risk management contracts on the consolidated balance sheet.

As at December 31, 2017 and December 31, 2016, Athabasca's cash, cash equivalents and restricted cash were held with five counterparties. All counterparties were large reputable financial institutions. The Company believes that credit risk associated with these investments is low. Management believes collection risk on the outstanding accounts receivable as at December 31, 2017 is low given the high credit quality of the Company's material counterparties. No material amounts were past due at December 31, 2017. The capital-carry receivable is considered to have low credit risk given the high credit quality of the Murphy subsidiary that has guaranteed the obligation. As at December 31, 2017, Athabasca's risk management contracts were held with five counterparties, all of which were large reputable financial institutions. The Company believes that credit risk associated with risk management contracts is low.

Interest Rate Risk

The Company's exposure to interest rate fluctuations on interest earned on its floating rate cash balance of $276.7 million (December 31, 2016 - $757.3 million), from a 1.0% change in interest rates, would be approximately $2.8 million for a 12 month period (year ended December 31, 2016 - $7.6 million). The 2022 Notes are subject to a fixed interest rate of 9.875% per annum and are not exposed to changes in interest rates.

Other Corporate Items

Interest Income and Other

($ Thousands)	Three months ended December 31, 2017	Three months ended December 31, 2016	Year ended December 31, 2017	Year ended December 31, 2016
Interest on cash, cash equivalents and short-term investments	$ 931	$ 1,817	$ 3,552	$ 6,282
Interest on promissory notes	—	—	—	1,555
Accretion of capital-carry receivable	2,756	3,062	11,672	7,967
Other	—	22	—	14
TOTAL INTEREST INCOME AND OTHER	$ 3,687	$ 4,901	$ 15,224	$ 15,818

During the year ended December 31, 2017, interest income on cash, cash equivalents, short-term investments and promissory notes decreased by $4.3 million compared to the prior year primarily due to lower average balances across all instruments.

For the three months and year ended December 31, 2017, Athabasca recognized $2.8 million and $11.7 million, respectively (2016 - $3.1 million and $8.0 million, respectively) in non-cash interest income from the time value of money accretion on the Company's capital-carry receivable from Murphy.

General and Administrative ("G&A")

($ Thousands, unless otherwise noted)	Three months ended December 31, 2017	Three months ended December 31, 2016	Year ended December 31, 2017	Year ended December 31, 2016
TOTAL GENERAL AND ADMINISTRATIVE	$ 9,039	$ 7,789	$ 29,168	$ 26,221
G&A per boe	$ 2.34	$ 7.28	$ 2.26	$ 5.98

During the three months and year ended December 31, 2017, Athabasca's general and administrative expenses increased compared to the same periods in the prior year, primarily reflecting higher employee costs related to the Leismer Corner Acquisition. However, for the same time periods, G&A per boe decreased 68% and 62% primarily due to the significant 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.

Stock-based Compensation

During the year ended December 31, 2017, stock-based compensation expense decreased to $7.0 million compared to $10.1 million in the prior year. The decrease is primarily due to a lower deferred share units expense and a higher capitalization rate of stock based compensation expense based on current activity.

Gain (loss) on Revaluation of Provisions and Other

($ Thousands)	Three months ended December 31, 2017	Three months ended December 31, 2016	Year ended December 31, 2017	Year ended December 31, 2016
Contingent payment obligation - changes in estimates	$ (15,763)	$ —	$ (1,548)	$ —
Capital-carry receivable - changes in estimates	2,850	(284)	2,637	371
Other	(196)	936	595	1,502
TOTAL GAIN (LOSS) ON REVALUATION OF PROVISIONS AND OTHER	$ (13,109)	$ 652	$ 1,684	$ 1,873

The loss on revaluation of provisions and other in the fourth quarter of 2017 was primarily a result of a $15.8 million loss recognized on the Company's contingent payment obligation to Statoil due to an increase in the forecasted price for WTI from September 30, 2017 to December 31, 2017. The contingent payment obligation is remeasured at each reporting period with any gains or losses recognized in net income (loss). No amounts are currently payable with respect to the continent payment obligation.

Deferred income tax recovery

As at December 31, 2017 and 2016, Athabasca was in a net unrecognized deferred tax asset position. The deductible temporary differences in excess of taxable temporary differences are approximately $1.5 billion (December 31, 2016 - $1.3 billion). Since Athabasca has not recognized the benefit of these deductible temporary differences, no deferred tax recovery was recognized during the years ended December 31, 2017 and 2016.

As at December 31, 2017, the Company has approximately $2.9 billion in tax pools, including $1.7 billion in non-capital losses and exploration pools available for immediate deduction against future income.

Environmental Initiatives 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.

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

On January 31, 2017, Athabasca issued 100 million common shares to Statoil in respect of the Leismer Corner Acquisition. During the year ended December 31, 2017, Athabasca also issued 3.6 million common shares in respect of the Company’s equity-settled share-based compensation plans.

Outstanding Share Data

The following table summarizes the number of share capital instruments outstanding at the date indicated:

As at February 28, 2018	
Common shares issued and outstanding	510,230,393
Convertible securities:	
Stock options	10,941,166
Restricted share units (2010 RSU Plan)	2,484,156
Restricted share units (2015 RSU Plan)	8,850,168
Performance share units	3,291,967
Deferred share units	1,531,274

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:

	2017				2016			
($ Thousands, unless otherwise noted)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	55.40	48.21	48.29	51.91	49.29	44.94	45.59	33.45
WTI (C$/bbl)	70.47	60.35	64.95	68.52	65.56	58.87	58.81	45.83
Western Canadian Select (C$/bbl)	54.87	47.76	49.99	49.34	46.61	41.01	41.62	26.30
Edmonton Par (C$/bbl)	69.02	56.62	61.92	63.87	61.59	54.66	54.78	40.67
Edmonton Condensate (C5+) (C$/bbl)	73.74	59.01	65.15	68.73	63.38	55.31	56.80	46.32
AECO (C$/GJ)	1.60	1.38	2.64	2.55	2.93	2.20	1.32	1.74
NYMEX Henry Hub (US$/MMBtu)	2.93	3.00	3.19	3.32	2.98	2.81	1.95	2.09
Foreign exchange (USD : CAD)	1.27	1.25	1.34	1.32	1.33	1.31	1.29	1.37
LIGHT OIL DIVISION								
Sales volumes (boe/d)	11,507	7,875	7,246	3,421	3,337	3,018	5,743	6,319
Realized price ($/boe)	34.22	32.91	36.69	38.97	35.99	29.84	26.93	21.73
Revenues ($)[2]	34,598	21,646	22,956	11,578	10,484	8,086	13,595	11,943
Light Oil Operating Income ($)[1]	26,696	13,748	16,391	6,863	6,152	5,511	7,215	4,908
Light Oil Operating Netback ($/boe)[1]	25.22	18.98	24.85	22.28	20.04	19.85	13.80	8.53
Capital expenditures ($)	40,988	53,406	31,061	77,646	62,003	18,920	5,518	30,658
Capital expenditures net of capital-carry ($)[1]	21,806	47,314	17,568	66,966	61,951	14,634	4,044	30,658
THERMAL OIL DIVISION								
Bitumen production (bbl/d)	30,557	28,258	29,328	23,316	8,293	8,830	5,358	7,029
Sales volumes (bbl/d)	29,447	28,640	28,970	23,257	8,015	9,744	4,463	7,176
Realized bitumen price ($/bbl)	35.72	33.38	31.82	29.41	31.46	28.56	24.51	7.27
Revenues ($)[2]	194,324	160,056	175,291	138,098	44,058	45,124	19,386	21,076
Thermal Oil Operating Income (Loss) ($)[1]	45,385	38,610	27,396	12,341	(4,719)	(6,088)	(11,915)	(23,074)
Thermal Oil Operating Netback ($/bbl)[1]	16.75	14.66	10.39	5.89	(6.41)	(6.80)	(29.33)	(35.34)
Capital expenditures ($)	11,368	20,382	14,127	10,868	4,088	3,754	2,187	916
OPERATING RESULTS								
Cash Flow from Operating Activities ($)	37,060	49,488	28,049	(52,896)	(19,656)	(18,990)	5,759	(38,017)
Adjusted Funds Flow ($)[1]	41,808	34,400	27,567	(1,649)	(16,867)	(15,778)	(27,304)	(39,982)
Net income (loss) ($)	(209,588)	5,113	24,233	(29,162)	(779,405)	(33,032)	(59,169)	(65,129)
Net income (loss) per share - basic ($)	(0.41)	0.01	0.05	(0.06)	(1.92)	(0.08)	(0.15)	(0.16)
BALANCE SHEET ITEMS								
Cash and cash equivalents ($)	163,321	174,076	179,611	212,999	650,301	535,477	447,282	493,510
Short-term investments ($)	—	—	—	—	—	35,000	25,533	—
Restricted cash ($)	113,406	113,372	113,853	113,823	107,012	103,827	101,652	—
Capital-carry receivable (discounted) ($)[3]	156,036	169,611	173,714	183,745	191,174	188,448	188,742	—
Promissory notes ($)[3]	—	—	—	—	—	—	133,892	133,892
Assets held for sale ($)	—	—	—	—	—	—	—	466,159
Total assets ($)	2,323,572	2,498,740	2,488,995	2,524,187	2,257,887	3,017,285	3,028,938	3,394,367
Long-term debt ($)[3]	526,206	523,782	541,199	553,377	546,209	545,126	544,042	820,478
Shareholders' equity ($)	1,524,610	1,731,546	1,723,735	1,695,582	1,557,097	2,333,523	2,363,396	2,419,651

(1) Refer to "Advisories and Other Guidance" beginning on page 24 for additional information on Non-GAAP financial measures.
(2) Consists of petroleum and natural gas sales, net of royalties. Excludes interest income and other.
(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.

SELECTED ANNUAL INFORMATION

The following table provides a summary of selected annual information for the years ended 2017, 2016 and 2015:

($ Thousands, unless otherwise noted)[1]	December 31, 2017	December 31, 2016	December 31, 2015
Petroleum and natural gas volumes (boe/d)	35,421	11,981	7,560
Petroleum and natural gas sales	$ 770,172	$ 176,110	$ 83,848
Net loss and comprehensive loss	$ (209,407)	$ (936,734)	$ (696,771)
per share (basic and diluted)	$ (0.42)	$ (2.31)	$ (1.73)
Cash flow from operating activities	$ 61,697	$ (70,968)	$ (67,826)
per share (basic)	$ 0.12	$ (0.17)	$ (0.17)
Adjusted Funds Flow[1]	$ 102,123	$ (101,502)	$ (47,003)
per share (basic)	$ 0.20	$ (0.25)	$ (0.12)
Capital expenditures[2]	$ 262,048	$ 128,079	$ 291,667
Capital expenditures net of capital-carry[1][2]	$ 212,601	$ 122,267	$ 291,667
Total assets	$ 2,323,572	$ 2,257,887	$ 3,462,442
Face value of long-term debt (current and long-term portions)[3]	$ 563,310	$ 550,000	$ 856,759
Weighted average shares outstanding (basic and diluted)	500,136,092	405,621,706	403,214,050

(1) Refer to "Advisories and Other Guidance" beginning on page 24 for additional information on Non-GAAP Financial Measures.
(2) Capital expenditures excludes the cost of the Leismer Corner Acquisition (see page 10).
(3) Face value of the US dollar denominated 2022 Notes as at December 31, 2017 is US$450 million. The 2022 Notes were translated into Canadian dollars at the period end exchange rate of US$1.00 = C$1.2518.

ACCOUNTING POLICIES AND ESTIMATES

During the year ended December 31, 2017, 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. A summary of the significant accounting polices used by Athabasca can be found in Note 3 of the December 31, 2017 consolidated financial statements. For the year ended December 31, 2017, Athabasca's significant estimates and judgments are as follows:

Significant Accounting Estimates and Judgments

The preparation of the consolidated financial statements requires management to use estimates, judgments and assumptions. These judgments and assumptions affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the applicable reporting period. These estimates relate to unsettled transactions and events as of the date of the consolidated financial statements and may differ from actual results as future confirming events occur. Estimates and underlying assumptions are reviewed by management on an ongoing basis. Revisions to accounting estimates are recognized prospectively in the year in which the estimates are revised. Changes in the Company's accounting estimates and judgments could have a significant impact on net income (loss).

Included in the carrying value of property, plant and equipment ("PP&E") are accumulated depletion, depreciation and impairment charges that are determined, in part, by utilizing estimates based on Athabasca's reserves, resources, relevant market transactions and land acreage values. The estimates of reserves and resources include estimates of the recoverable volumes of oil, gas, NGLs and bitumen, future commodity prices and future costs required to develop and produce the assets. Reserve and resource estimates and future cash flows could be revised either upwards or downwards based on updated information from drilling and operating results as well as changes to future commodity price estimates, changes in cost estimates and changes to the anticipated timing of project development. The rates used to discount future cash flows are based on judgment of economic and operating factors. Changes in these factors could increase or decrease the discount rate which may result in material changes to the estimated recoverable amount of the assets. Exploration and evaluation assets ("E&E") require judgment as to whether future economic benefits exist, including the estimated recoverability of contingent resources, technology uncertainty and the ability to finance exploration and evaluation projects, where technical feasibility and commercial viability has not yet been determined.

For purposes of impairment testing, PP&E and E&E are aggregated into cash-generating units ("CGUs"), based on separately identifiable and largely independent cash inflows. The determination of the Company's CGUs is subject to judgment. Factors considered in the classification of CGUs include the integration between assets, shared infrastructures, the existence of common sales points, geography, geologic structure and the manner in which management monitors and makes decisions regarding operations. CGUs are not larger than an operating segment.

The capital-carry receivable includes estimates for the anticipated timing of capital expenditures and the credit-adjusted discount rate. The timing of actual cash inflows could differ from the estimates as a result of changes in the timing of the Greater Kaybob area development plan.

The Company evaluates the carrying value of its inventory at the lower of cost and net realizable value. The net realizable value is estimated based on anticipated current market prices that Athabasca would expect to receive from the sale of its inventory.

The provision for decommissioning obligations is based upon numerous assumptions including the ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. Actual costs and cash outflows could differ from the estimates as a result of changes in any of the above noted assumptions.

The provision for the contingent payment obligation is based upon numerous assumptions including anticipated timing and extent of future cash outflows associated with the obligation using forecasted WTI prices, inflation factors, foreign exchange rates, Leismer bitumen sales and credit-adjusted discount rates. Actual cash outflows could differ from the estimates as a result of changes in any of the above noted assumptions.

The provision for income taxes is based on judgments in applying income tax law and estimates on the timing and likelihood of reversal of temporary differences between the accounting and tax bases of assets and liabilities. The provision for income taxes is based on Athabasca's interpretation of the tax legislation and regulations which are also subject to change. Athabasca recognizes a tax provision when a payment to tax authorities is considered more likely than not. Income tax filings are subject to audits and re-assessments and changes in facts, circumstances and interpretations of the standards which may result in a material increase or decrease in the Company's provision for income taxes. As at December 31, 2017 and as at December 31, 2016, Athabasca did not recognize deductible temporary differences in respect of income tax assets.

Business combinations are accounted for using the acquisition method of accounting. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of PP&E and E&E assets acquired generally require the most judgment and include estimates of reserves acquired, forecast benchmark commodity prices and discount rates. Assumptions are also required to determine the fair value of decommissioning obligations associated with the properties. Changes in any of the assumptions or estimates used in determining the fair value of the acquired assets and liabilities could impact the amounts assigned to the assets and liabilities in the acquisition equation. Future net income (loss) can be affected as a result of changes in future depletion, depreciation or asset impairment.

The Company utilizes commodity risk management contracts to manage its commodity price risk on its petroleum and natural gas sales. The calculated fair value of the risk management contracts relies on external observable market data including quoted forward commodity prices. The resulting fair value estimates may not be indicative of the amounts actually realized at settlement and as such are subject to measurement uncertainty.

Stock-based compensation includes volatility, option life and forfeiture rates which are based on management's assumptions and estimates.

All of these estimates are subject to measurement uncertainty and changes in these estimates could materially impact the financial statements of future periods and have a significant impact on net income (loss).

Future Accounting Pronouncements

The following standards that have been issued, but are not yet effective, up to the date of issuance of the Company's consolidated financial statements are disclosed below. The Company intends to adopt these standards, if applicable, when they become effective.

IFRS 15 *Revenue from Contracts with Customers*
The IASB issued IFRS 15 *Revenue from Contracts with Customers* 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. The Company has completed its review of its various revenue streams and related contracts and has concluded IFRS 15 will not have a material impact on its consolidated financial statements outside of additional disclosure. Athabasca intends to retroactively adopt IFRS 15 on January 1, 2018.

IFRS 9 *Financial Instruments*
In July 2014, the IASB issued the final version of IFRS 9 *Financial Instruments* that replaces 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. The Company has concluded IFRS 9 will not have a material impact on its consolidated financial statements and intends to adopt the new standard on January 1, 2018.

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 and years ended December 31, 2017 and 2016 to Adjusted Funds Flow:

	Three months ended December 31,		Year ended December 31,	
($ Thousands)	2017	2016	2017	2016
Cash flow from operating activities	$ 37,060	$ (19,656)	$ 61,697	$ (70,968)
Acquisition expenses	—	—	11,047	—
Receipt of proceeds from derivative unwind	—	—	—	(40,956)
Changes in non-cash working capital	2,134	1,505	20,732	4,577
Settlement of provisions	2,614	1,284	8,647	5,845
ADJUSTED FUNDS FLOW	$ 41,808	$ (16,867)	$ 102,123	$ (101,502)

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 9 reconciles Light Oil Operating Income to *Note 16 - Segmented Information* in the consolidated financial statements for the year ended December 31, 2017.

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 13 reconciles Thermal Oil Operating Income (Loss) to *Note 16 - Segmented Information* in the consolidated financial statements for the year ended December 31, 2017.

The Consolidated Operating Income (Loss) and Consolidated Operating Netback measures in this MD&A are calculated by subtracting realized 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 6 reconciles Consolidated Operating Income (Loss) to *Note 16 - Segmented Information* in the consolidated financial statements for the year ended December 31, 2017.

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 7 and 9. 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.

Disclosure Controls and Procedures

Disclosure controls and procedures ("DC&P") are designed to provide reasonable assurance that the information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under the applicable Canadian securities regulatory requirements.

Part 1 of NI 52-109 defines DC&P as "Controls and other procedures of an issuer that are designed to provide reasonable assurance that information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by an issuer in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the issuer's management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure".

For the year ended December 31, 2017, an evaluation was carried out under the supervision of and with the participation of Athabasca's management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of the Company's DC&P. Based upon that evaluation, the Chief Executive Officer and the Chief Financial Officer of the Company concluded that the design and operation of the Company's DC&P were effective to ensure that the information required by Canadian securities regulatory authorities, will be recorded, processed, summarized and reported within the prescribed timelines.

Management's Report on Internal Control over Financial Reporting

Management of Athabasca is responsible for establishing and maintaining adequate "internal control over financial reporting" as such term is defined in the applicable Canadian securities regulations. The Company's policies and procedures regarding internal controls over financial reporting were designed by the Company's management, with the oversight of the Chief Executive Officer and the Chief Financial Officer, to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of the Company's financial statements in accordance with IFRS.

The Company has policies and procedures with respect to internal control over financial reporting that:

- pertain to the maintenance of records, to ensure that dispositions of assets and other material transactions involving the Company are accurately and fairly reflected in a reasonable level of detail in the Company's records;
- provide reasonable assurance that transactions are recorded as necessary to ensure that the preparation of the financial statements is done in accordance with IFRS; and
- provide reasonable assurance regarding the timely detection and prevention of unauthorized acquisitions, uses or dispositions of the Company's assets which could have a material impact on the Company and its financial statements.

Athabasca's policies and procedures regarding internal control over financial reporting may not detect or prevent all inaccuracies, omissions or misstatements. A control system, no matter how well conceived or operated, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with the Company's policies and procedures.

Management, including the Chief Executive Officer and Chief Financial Officer, must assess the effectiveness of the Company's internal control over financial reporting as of December 31, 2017, based on the Internal Control - Integrated Framework (the "Framework") established by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In making its assessment, Management used the COSO 2013 Framework in order to evaluate the design and effectiveness of internal control over financial reporting. Based upon management's assessment, the Company has maintained effective internal control over financial reporting as of December 31, 2017.

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, including the Leismer Corner Acquisition;
- 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 to nameplate capacity;
- 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 New 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 New 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; estimates of future depletion rates on the Hangingstone and Leismer Projects; 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; the timing for achievement of name plate capacity at the Hangingstone Project the timing of facilities construction and in service dates and the capacity thereof; 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 New 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 New 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 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 7 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 7 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 is reporting 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 areas for 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