ATHABASCA OIL CORPORATION

Management's Discussion and Analysis

Q1 2016

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Management's Discussion and Analysis

This Management's Discussion and Analysis of the financial condition and results of operations ("MD&A") of Athabasca Oil Corporation ("Athabasca" or the "Company") is dated May 6, 2016 and should be read in conjunction with the audited consolidated financial statements of the Company for the years ended December 31, 2015 and 2014 and the unaudited condensed interim consolidated financial statements of the Company for the three months ended March 31, 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 17 of this MD&A. See "Reserves and Resource information" on page 19 for important information regarding the Company's reserves and resources information included in this MD&A. For a listing of abbreviations, refer to "Abbreviations" on page 20 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 10, 2016 ("AIF"). The Company's common shares are listed on the Toronto Stock Exchange under the trading symbol "ATH".

BUSINESS OVERVIEW

The Company is focused on the exploration and development of unconventional oil resource plays in Alberta, Canada. Athabasca is organized into two divisions:

Light Oil

Athabasca produces light oil and liquids-rich natural gas from unconventional reservoirs utilizing horizontal drilling and multi-stage hydraulic fracturing technology. Development has been focused in Saxon/Placid (the "Greater Placid area") and Kaybob ("Greater Kaybob area") near the town of Fox Creek, Alberta. Athabasca has 25,000 gross acres of commercially prospective Montney lands within the Greater Placid area and has identified a potential inventory of more than 165[(1)] gross drilling locations. Athabasca also has over 200,000 gross acres of commercially prospective Duvernay lands in the Greater Kaybob area at various stages of delineation and development where the Company has identified a potential inventory of approximately 1,500[(1)] gross drilling locations. Development to date has resulted in the booking of approximately 65 MMboe[(2)(3)] of Proved plus Probable Reserves in Athabasca's Light Oil Division as of December 31, 2015. During the first quarter of 2016, the Light Oil Division produced 6,319 boe/d.

During the first quarter of 2016, Athabasca entered into a purchase and sale agreement with Murphy Oil Company Ltd. (the wholly owned Canadian subsidiary of Murphy Oil Corporation, "Murphy") to form a strategic joint venture to develop the Duvernay and Montney in the Greater Kaybob and Greater Placid areas. As part of the transaction, the Company is selling an operated 70% interest in the Greater Kaybob area and a non-operated 30% interest in the Greater Placid area[(3)] for gross proceeds of approximately $475.0 million. The Murphy Transaction is anticipated to close during the second quarter of 2016, subject to the parties meeting certain conditions.

Thermal Oil

Athabasca's Thermal Oil Division consists of four major project areas in the Athabasca region of Northeastern Alberta. The primary development focus is in the Hangingstone area where the Company is currently ramping up its first project, a 12,000 bbl/d SAGD project ("Project 1"). Development to date has resulted in the booking of approximately 225 MMbbl[(2)] of Proved plus Probable Reserves and 0.6 billion barrels (risked)[(2)] (0.8 billion barrels unrisked)[(2)] of Best Estimate Contingent Resources in the Hangingstone area. During the first quarter of 2016, the Thermal Oil Division produced 7,029 boe/d.

Athabasca's Thermal Oil exploration areas consist of Dover West Leduc Carbonates, Dover West Sands and Birch. Development targets include oil sands in the McMurray and Wabiskaw formations as well as carbonates in the Leduc formation. The Company expects to produce its recoverable bitumen from the exploration areas using in-situ recovery methods such as SAGD or other suitable experimental technologies such as TAGD. Development to date has resulted in the booking of approximately 3.0 billion barrels (risked)[(2)] (5.1 billion barrels unrisked)[(2)] of Best Estimate Contingent Resources in the Company's Thermal Oil Exploration areas.

(1) Refer to Advisories and Other Guidance beginning on page 16 for additional information regarding the Company's drilling locations.
(2) Based on the reports of Athabasca's independent reserve evaluators effective December 31, 2015. Refer to page 19 and the AIF for additional important information about the Company's Reserves and Contingent Resources.
(3) In the first quarter of 2016, Athabasca entered into the Murphy Transaction which is anticipated to result in the sale of approximately 38 MMboe of Proved plus Probable Reserves from the Light Oil Division. The transaction is expected to close in the second quarter of 2016, subject to the parties meeting certain conditions.

SELECTED FINANCIAL INFORMATION

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

Three months ended ($ Thousands, except per share and boe amounts)		March 31, 2016		March 31, 2015
CONSOLIDATED PRODUCTION				
Petroleum and natural gas volumes (boe/d)		13,348		5,877
LIGHT OIL DIVISION				
Petroleum and natural gas sales volumes (boe/d)		6,319		5,877
Light Oil Operating Income[1]	$	4,908	$	6,578
Light Oil Operating Netback[1] ($/boe)	$	8.53	$	12.46
Capital expenditures[2]	$	30,658	$	79,241
THERMAL OIL DIVISION				
Bitumen production (bbl/d)		7,029		—
Bitumen sales volumes (bbl/d)		7,176		—
Thermal Oil Operating Loss[1][3]	$	(23,074)	$	—
Thermal Oil Operating Netback ($/bbl)[1][3]	$	(35.34)	$	—
Capital expenditures	$	916	$	68,504
CASH FLOW AND FUNDS FLOW				
Cash flow from operating activities	$	(38,017)	$	(2,610)
Cash flow from operating activities per share (basic and diluted)	$	(0.09)	$	(0.01)
Funds Flow from Operations[1]	$	(39,982)	$	3,162
Funds Flow from Operations per share (basic and diluted)[1]	$	(0.10)	$	0.01
NET LOSS AND COMPREHENSIVE LOSS				
Net loss and comprehensive loss	$	(65,129)	$	(25,112)
Net loss and comprehensive loss per share (basic and diluted)	$	(0.16)	$	(0.06)
SHARES OUTSTANDING				
Weighted average shares outstanding (basic and diluted)		404,511,104		402,393,806
FINANCING AND DIVESTITURES				
Promissory note proceeds	$	—	$	300,000

(1) Refer to "Advisories and Other Guidance" beginning on page 16 for additional information on Non-GAAP Financial Measures.
(2) During the three months ended March 31, 2016, $8.7 million of Light Oil PP&E expenditures were classified as assets held for sale.
(3) Negative Operating Netbacks are customary during ramp-up of a SAGD project as revenues from lower initial production is more than offset by operating and transportation costs which are largely fixed in nature regardless of production volumes. Athabasca anticipates that operating and transportation costs per barrel from Project 1 will continue to materially improve as production increases.

As at ($ Thousands)		March 31, 2016		December 31, 2015
BALANCE SHEET ITEMS				
Cash and cash equivalents	$	493,510	$	559,487
Promissory note	$	133,892	$	133,892
Assets held for sale	$	466,159	$	—
Total assets	$	3,394,367	$	3,462,442
Long-term debt	$	820,478	$	838,205
Net debt[1]	$	209,809	$	154,711
Shareholders' equity	$	2,419,651	$	2,482,140

(1) Refer to "Advisories and Other Guidance" beginning on page 16 for additional information on Non-GAAP Financial Measures.

HIGHLIGHTS FOR THE THREE MONTHS ENDED MARCH 31, 2016

Corporate

- On January 27, 2016, Athabasca entered into a purchase and sale agreement to form a strategic joint venture with Murphy to develop the Montney and Duvernay Formations in the Greater Kaybob and Greater Placid areas. As part of the transaction, Athabasca is selling 70% of its interest in its Greater Kaybob area assets and 30% of its interest in its Greater Placid area assets for gross proceeds of approximately $475.0 million (the "Murphy Transaction"). Murphy will assume operatorship of the Greater Kaybob area assets and Athabasca will retain operatorship of the Greater Placid area assets under separate joint development agreements. Athabasca will also retain operatorship of the regional midstream infrastructure in the near term.

  Murphy will pay approximately $250.0 million in cash to Athabasca on the transaction closing date, excluding purchase price adjustments from the January 1, 2016 effective date. Additional consideration of approximately $225.0 million will be in the form of a capital carry in the Greater Kaybob area whereby Murphy will fund 75% of Athabasca's share of development capital up to a maximum five year period. The carry supports up to approximately $1 billion of investment of which Athabasca's financial exposure is limited to $75 million to retain its 30% working interest in 200,000 gross acres. The Murphy Transaction is anticipated to close in the second quarter of 2016, subject to the parties meeting certain conditions.

- For the three months ended March 31, 2016, Athabasca produced 13,348 boe/d from the Company's Light Oil and Thermal Oil Divisions, a 127% increase compared to 5,877 boe/d during the same period in the prior year. The net increase in production was primarily due to commencement of production at Hangingstone Project 1 during the third quarter of 2015.

- As at March 31, 2016, Athabasca had liquidity of $627.4 million including cash and cash equivalents of $493.5 million and a promissory note for $133.9 million due in the third quarter of 2016. Following the closing of the Murphy Transaction, Athabasca anticipates that the Company will have approximately $880 million of liquidity (including cash, cash equivalents and the promissory note).

Light Oil Division

- For the three months ended March 31, 2016, Athabasca produced 6,319 boe/d (50% liquids) in the Light Oil Division, an 8% increase compared to 5,877 boe/d (49% liquids) during the same period in the prior year. The increase in production was primarily due to new wells brought on stream during the fourth quarter of 2015 and the first quarter of 2016.

- For the three months ended March 31, 2016, Athabasca's Light Oil Operating Netback[(1)] was $8.53/boe, compared to $12.46/boe during the same period in the prior year. The decrease in the Light Oil Operating Netback[(1)] were primarily due to lower underlying commodity prices.

- Athabasca spent $30.7 million in the Light Oil Division during the three months ended March 31, 2016. In the Greater Placid area, Athabasca completed three and brought on stream four Montney wells that had been drilled in the prior year. Additionally, during the first quarter of 2016, Athabasca completed construction and commissioning of a pipeline that connects the Company's Montney developments in the Greater Placid area to its existing delivery infrastructure at Saxon. In the Greater Kaybob area, the Company completed the drilling of a four-well Duvernay pad and brought two Duvernay wells on stream that had been drilled and completed in the prior year.

Thermal Oil Division

- During the three months ended March 31, 2016, Athabasca's bitumen production averaged 7,029 bbl/d in the Thermal Oil Division, a 23% increase compared to the fourth quarter of 2015. By the end of the first quarter, 23 of the 25 well pairs had been converted to production. The Company remains on track to achieve design capacity of 12,000 bbl/d at Project 1 in the fourth quarter of 2016.

- The Thermal Oil Operating Netback for the three months ended March 31, 2016 was $(35.34)/bbl, a 27% improvement compared to the fourth quarter of 2015, primarily due to higher production volumes. Negative Operating Netbacks are customary during ramp-up of a SAGD project as revenues from lower initial production are more than offset by operating and transportation costs which are largely fixed in nature regardless of production volumes. Athabasca anticipates that operating and transportation costs per barrel will continue to materially improve as Project 1 production increases.

(1) Refer to "Advisories and Other Guidance" beginning on page 16 for additional information on Non-GAAP Financial Measures.

RESULTS OF OPERATIONS

Business Environment

The following table summarizes the key commodity price benchmarks for the three months ended March 31, 2016 and 2015:

Monthly average Three months ended ($ Thousands)		March 31, 2016		March 31, 2015
Crude Oil:				
West Texas Intermediate (WTI) (US$/bbl)	$	33.45	$	48.63
Western Canadian Select (WCS) (C$/bbl)	$	26.30	$	42.14
Differential - WTI vs. WCS (US$/bbl)	$	(14.25)	$	(14.65)
Edmonton Par (C$/bbl)	$	40.67	$	51.79
Edmonton Condensate (C5+) (C$/bbl)	$	46.32	$	55.42
Natural gas:				
NYMEX Henry Hub (US$/MMBtu)	$	2.09	$	2.98
AECO (C$/GJ)	$	1.74	$	2.61
Foreign exchange (monthly average):				
USD : CAD		1.37		1.24

The price of WTI for crude oil sales at Cushing, Oklahoma is the primary benchmark for crude oil production in North America. The price Athabasca receives for its oil production in both its Light Oil and Thermal Oil Divisions is primarily driven by the price of WTI, adjusted to Western Canada. The WTI price is also used by the Province of Alberta for determining royalty rates on Athabasca's sales. For the three months ended March 31, 2016, the WTI price declined by US$15.18/bbl, or 31%, compared to the same period in the prior year primarily due to continuing global over-supply of petroleum and natural gas production.

The WCS price at Hardisty, Alberta is the primary benchmark for Athabasca's blended bitumen sales. The WCS price normally trades at a higher differential to the WTI price compared to lighter crude oil products. For the three months ended March 31, 2016 and 2015, WCS traded at an average differential below the WTI benchmark price of US$14.25/bbl and $14.65/bbl, respectively.

During the quarter ended March 31, 2016, the value of the Canadian dollar declined relative to the US dollar by 10% compared to the same period in the prior year. As North American crude oil prices are primarily set by U.S. benchmark prices, declines in the value of the Canadian dollar relative to the US dollar partially offset the negative impact of declining oil prices.

The Edmonton Par price and Edmonton Condensate (C5+) price are the primary benchmarks for crude oil, condensate and natural gas liquids sales in the Company's Light Oil Division. In the Thermal Oil Division, the Edmonton Condensate (C5+) price is the primary benchmark for diluent purchases which Athabasca consumes in the blending process at Project 1 in order to deliver produced bitumen to the market. For the three months ended March 31, 2016, the average Edmonton par price declined by $11.12/bbl compared to the same period in the prior year. For the three months ended March 31, 2016, the average Edmonton Condensate (C5+) price declined by $9.10/bbl.

During the three months ended March 31, 2016, the AECO price was $2.09/GJ (March 31, 2015 - $2.98/GJ). In the Thermal Oil Division, the AECO price is the primary benchmark for natural gas purchases consumed by Athabasca in order to generate steam which is used for the SAGD recovery process. The AECO gas price was also the primary benchmark for Athabasca's natural gas sales in the Light Oil Division during the first quarter of 2015 as Athabasca primarily delivered its sales product on the Alliance pipeline. In the fourth quarter of 2015, Athabasca began delivering sales product on the Fort Chicago pipeline and the NYMEX gas price became the primary benchmark for natural gas sales in the Light Oil Division. For the three months ended March 31, 2016, the NYMEX price was US$1.74/MMBtu (March 31, 2015 - US$2.61/MMBtu).

Athabasca typically realizes lower prices for its oil and gas sales compared to benchmark prices as a result of transportation costs, discounts received due to limited North American pipeline capacity and quality differentials.

Light Oil Division

Operating Results

The following tables summarize the Light Oil operating results for the three months ended March 31, 2016 and 2015:

Three months ended		March 31, 2016		March 31, 2015
SALES VOLUMES				
Oil (bbl/d)		2,530		2,308
Natural gas (Mcf/d)		18,993		18,126
Natural gas liquids (bbl/d)		623		548
Total (boe/d)		6,319		5,877
Oil and Natural gas liquids %		50%		49%
REALIZED PRICES				
Oil ($/bbl)	$	36.85	$	46.75
Natural gas ($/Mcf)		1.65		2.79
Natural gas liquids ($/bbl)		20.41		25.17
Realized price ($/boe)		21.73		29.35
Royalties ($/boe)		(0.96)		(3.52)
Operating and transportation expenses(1) ($/boe)		(12.24)		(13.37)
LIGHT OIL OPERATING NETBACK(2) ($/boe)	$	8.53	$	12.46

(1) For the three months ended March 31, 2016, operating and transportation expenses include midstream revenues of $0.86/boe (March 31, 2015 - $0.62).
(2) Refer to "Advisories and Other Guidance" beginning on page 16 for additional information on Non-GAAP Financial Measures.

Three months ended ($ Thousands)		March 31, 2016		March 31, 2015
Petroleum and natural gas sales	$	12,492	$	15,511
Midstream revenue		497		331
Royalties		(549)		(1,861)
Operating and transportation expenses		(7,532)		(7,403)
LIGHT OIL OPERATING INCOME(1)	$	4,908	$	6,578

(1) Refer to "Advisories and Other Guidance" beginning on page 16 for additional information on Non-GAAP Financial Measures.

During the three months ended March 31, 2016, Athabasca produced 6,319 boe/d (50% liquids), an 8% increase compared to 5,877 boe/d (49% liquids) during the same period in the prior year. The increase was primarily due to new wells brought on stream during 2015 and the first quarter of 2016. Athabasca brought four Duvernay wells on stream in the fourth quarter of 2015 and six wells on stream in the first quarter of 2016 (four Montney, two Duvernay). The increase was partially offset by lower production from natural well declines from the Company's existing wells as well as pipeline restrictions on the TCPL transportation system during the first quarter of 2016.

Realized prices decreased by 26% during the three months ended March 31, 2016 to $21.73/boe compared to the same period in the prior year. The declines were primarily due to lower underlying market commodity prices for oil, natural gas and natural gas liquids.

Royalty expenses for the quarter ended March 31, 2016 were $0.5 million (4% of revenue) compared to $1.9 million (12% of revenue) during the same period in the prior year. Declines in royalty expenses were primarily due to lower royalty rates which declined due to lower market commodity prices.

Compared to the same period in the prior year, operating and transportation expenses decreased from $13.37/boe to $12.24/boe during the three months ended March 31, 2016, primarily due to higher production from new wells brought on stream in 2015 and the first quarter of 2016.

Segment Income (Loss)

The following table summarizes the Light Oil Segment income (loss) for the three months ended March 31, 2016 and 2015:

Three months ended ($ Thousands)	March 31, 2016	March 31, 2015
Light Oil Operating Income(1)	$ 4,908	$ 6,578
Depletion and depreciation	(10,829)	(17,387)
Exploration expense and other	18	(83)
LIGHT OIL SEGMENT LOSS	$ (5,903)	$ (10,892)

(1) Refer to "Advisories and Other Guidance" beginning on page 16 for additional information on Non-GAAP Financial Measures.

Depletion and depreciation

Three months ended ($ Thousands)	March 31, 2016	March 31, 2015
Depletion of oil and gas assets	$ 10,373	$ 16,263
Depreciation of infrastructure assets	456	1,124
TOTAL LIGHT OIL DEPLETION AND DEPRECIATION	$ 10,829	$ 17,387

Depletion of oil and gas assets declined by $5.9 million during the three months ended March 31, 2016 compared to the same period in the prior year, primarily due to lower depletion rates resulting from reserve additions in the Light Oil Division, partially offset by higher production volumes during the first quarter of 2016. Depletion and depreciation also declined due to lower average carrying values of property, plant and equipment in the Light Oil Division as a result of impairment losses incurred during the fourth quarter of 2015.

The producing Light Oil properties, including estimated future development costs, are depleted using a unit-of-production method based on estimated Proved plus Probable Reserves. Major infrastructure, including the division's oil batteries, gas processing facilities and delivery infrastructure, are depreciated on a straight-line basis over the estimated useful life of the components.

Thermal Oil Division

Operating results

The following tables summarizes the Thermal Oil operating results for the three months ended March 31, 2016 and 2015:

Three months ended	March 31, 2016	March 31, 2015
VOLUMES		
Bitumen production (bbl/d)	7,029	—
Bitumen sales (bbl/d)	7,176	—
Blended bitumen sales (bbl/d)	10,175	—
REALIZED PRICES		
Blended bitumen sales ($/bbl)	$ 22.79	$ —
Bitumen sales ($/bbl)	$ 7.27	$ —
Royalties ($/bbl)	(0.04)	—
Operating expenses - non-energy ($/bbl)	(24.60)	—
Operating expenses - energy ($/bbl)	(5.24)	—
Transportation and marketing ($/bbl)	(12.73)	—
THERMAL OIL OPERATING NETBACK(1) ($/bbl)	$ (35.34)	$ —

(1) Refer to "Advisories and Other Guidance" beginning on page 16 for additional information on Non-GAAP Financial Measures.

Three months ended ($ Thousands)		March 31, 2016		March 31, 2015
Blended bitumen sales	$	21,101	$	—
Cost of diluent		(16,356)		—
Total bitumen sales		4,745		—
Royalties		(25)		—
Operating expenses - non-energy		(16,063)		—
Operating expenses - energy		(3,420)		—
Transportation and marketing		(8,311)		—
THERMAL OIL OPERATING INCOME (LOSS)[1]	$	(23,074)	$	—

(1) Refer to "Advisories and Other Guidance" beginning on page 16 for additional information on Non-GAAP Financial Measures.

During the three months ended March 31, 2016, Athabasca continued to ramp-up Project 1 averaging 7,029 bbl/d of bitumen production, a 23% increase compared to the fourth quarter of 2015.

During the first quarter of 2016, Athabasca performed both planned and unplanned maintenance activities to bring overall production reliability to expected performance levels. Facility maintenance activities included process vessel cleaning as well as minor plant and control system modifications. Sub-surface maintenance included adjustments to steam injection control as well as a production pump change. The maintenance work was successful, however, these activities impacted production volumes during the quarter while the work was conducted. Reservoir performance continues to align with subsurface modeling as the project ramps up and the SOR is declining as the steam chambers mature. By the end of the first quarter, 23 of the 25 well pairs had been converted to production. The Company remains on track to achieve design capacity of 12,000 bbl/d in the fourth quarter of 2016.

The Thermal Oil Operating Netback for the three months ended March 31, 2016 was $(35.34)/bbl, a 27% increase compared to $(48.22)/bbl during the fourth quarter of 2015. The improvement in the Thermal Oil Operating Netback was primarily due to higher production volumes as the project continued to ramp-up during the first quarter, partially offset by lower underlying market commodity prices for bitumen during the first quarter of 2016 compared to the fourth quarter of 2015.

Negative Operating Netbacks are customary during ramp-up of a SAGD project as revenues from lower initial production are more than offset by operating and transportation costs which are largely fixed in nature regardless of production volumes. Athabasca anticipates that operating and transportation costs per barrel from Project 1 will continue to materially improve as production increases.

Operating costs consist of energy and non-energy related costs. Energy operating costs include natural gas which is used to create steam for the SAGD recovery process and electricity to power the facility. Non-energy operating costs consist of all other operational expenditures relating to lifting costs. Transportation and marketing expenditures primarily consist of take or pay commitments to deliver dilbit product from the plant facility to the Cheecham terminal and then to Edmonton. First sales from the dilbit pipeline were completed in January 2016.

Segment Income (Loss)

The following table summarizes the Thermal Oil Segment income (loss) for the three months ended March 31, 2016 and 2015:

Three months ended ($ Thousands)		March 31, 2016		March 31, 2015
Thermal Oil Operating Income[1]	$	(23,074)	$	—
Depletion and depreciation		(6,695)		—
Exploration expense		(147)		(233)
Gain on sale of assets		—		957
THERMAL OIL SEGMENT INCOME (LOSS)	$	(29,916)	$	724

(1) Refer to "Advisories and Other Guidance" beginning on page 16 for additional information on Non-GAAP Financial Measures.

Depletion and Depreciation

Three months ended ($ Thousands)	March 31, 2016	March 31, 2015
Depletion of oil and gas assets	$ 3,209	$ —
Depreciation of infrastructure assets	3,486	—
TOTAL THERMAL OIL DEPLETION AND DEPRECIATION	$ 6,695	$ —

During the third quarter of 2015, Project 1 became ready for use in the manner intended by management and Athabasca began depreciating the project components over their useful lives. The central processing facilities are depreciated on a unit-of-production basis over the total productive capacity of the facility. The supporting infrastructure is depreciated on a straight-line basis over the estimated useful life of the components. The producing oil sands properties, including estimated future development costs, are depleted using the unit-of-production method based on estimated Proved Reserves.

Corporate Review

General and Administrative ("G&A")

Three months ended ($ Thousands)	March 31, 2016	March 31, 2015
Salaries and benefits	$ 5,506	$ 10,466
Office costs	2,185	4,133
Legal, accounting and consulting	958	1,082
Stakeholder relations	332	391
Capitalized staff costs	(2,047)	(7,702)
TOTAL GENERAL AND ADMINISTRATIVE EXPENSES	$ 6,934	$ 8,370
Capitalization rate	23%	48%

During the three months ended March 31, 2016, salaries and benefits declined by 47% compared to the same period in prior year. The decline was primarily due to restructuring activities undertaken by the Company in 2015 to streamline costs and better align the organization's cost structure to the current operating environment, its capital plans and growth objectives.

Compared to the same period in the prior year, office costs declined by $1.9 million during the three months ended March 31, 2016 primarily due to office lease provisions previously recognized on under utilized space beginning in the second quarter of 2015. Lease payments relating to the office lease provisions reduce the corresponding office lease liability. Office costs also declined during the first quarter of 2016 as a result of ongoing cost saving initiatives and sub-lease recoveries.

Capitalized staff and environment costs decreased during the three months ended March 31, 2016 compared to the same period in the prior year, primarily due to staff reductions, the completion of Project 1 and a reduction in Thermal Oil and Light Oil capital activities.

Restructuring and Other Charges

There were no restructuring charges recognized during the first quarter of 2016. For the three months ended March 31, 2015, Athabasca incurred $17.0 million in restructuring and other charges including staff restructuring charges of $6.0 million, $7.0 million relating to lease commitments on vacated office space primarily as a result of the staff reductions and net cancellation charges of $4.0 million primarily relating to Thermal Oil rig commitments.

Stock-based Compensation

During the three months ended March 31, 2016, Athabasca incurred stock-based compensation expense of $1.6 million compared to $1.0 million during the same period in the prior year. Stock-based compensation expense increased primarily due to lower capitalization rates from reduced Thermal Oil and Light Oil capital activity in the first quarter of 2016. In addition, the Company recognized higher recoveries from forfeitures in the first quarter of 2015 as a result of staff restructuring activities.

Financing and Interest

Three months ended ($ Thousands)		March 31, 2016		March 31, 2015
Interest and fees on indebtedness	$	18,185	$	15,094
Accretion of provisions		1,959		1,839
Amortization of debt issuance costs		1,855		1,818
Capitalized financing and interest		—		(17,173)
TOTAL FINANCING AND INTEREST	$	21,999	$	1,578

Interest and financing expenses are primarily attributable to the three debt instruments held by the Company. Interest expense and amortization of debt issuance costs are incurred on the Company's $550.0 million senior secured second lien notes ("Notes") which were issued during the fourth quarter of 2012. The Notes bear interest at a rate of 7.5% per annum. Interest and amortization of debt issuance costs are also incurred on the Company's US$225.0 million senior secured first lien term loan (the "Term Loan") issued in the second quarter of 2014. The Term Loan currently bears interest at a rate of LIBOR plus 7.25%, subject to a 1% LIBOR floor. Athabasca also incurs standby fees and fees on issued letters of credit on its $125.0 million credit facility ("Credit Facility") and its US$50.0 million delayed-draw Term Loan.

During the three months ended March 31, 2016, Athabasca incurred higher interest and fees on indebtedness compared to the same period in the prior year. The increase was primarily due to an increase in letters of credit issued under the Company's Credit Facility.

In August of 2015, Athabasca discontinued the capitalization of interest and financing costs associated with Project 1 when the project became ready for use.

Interest Income and Other

Three months ended ($ Thousands)		March 31, 2016		March 31, 2015
Interest income on cash and cash equivalents	$	1,398	$	1,955
Interest income on promissory notes		589		2,056
Other		12		270
TOTAL INTEREST INCOME AND OTHER	$	1,999	$	4,281

During the three months ended March 31, 2016, interest income and other declined by $2.3 million compared to the same period in the prior year primarily due to higher average balances of cash, cash equivalents and promissory notes during the first quarter of 2015. Athabasca also earned higher interest income from higher interest rates during the first quarter of 2015.

Foreign Exchange Gain (Loss), Net

Three months ended ($ Thousands)		March 31, 2016		March 31, 2015
Unrealized foreign exchange gain (loss)	$	18,683	$	(23,672)
Realized foreign exchange gain		502		52
FOREIGN EXCHANGE GAIN (LOSS), NET	$	19,185	$	(23,620)

Athabasca incurs foreign exchange gains and losses on the Company's US$225.0 million Term Loan, which was issued on May 7, 2014. During the three months ended March 31, 2016, Athabasca recognized a net foreign exchange gain primarily due to an unrealized gain on the loan principal as the average value of the Canadian dollar increased relative to the US dollar by 6% from 1.38:1 to 1.30:1. During the three months ended March 31, 2015, Athabasca recognized a net foreign exchange loss primarily due to an unrealized loss on the loan principal as the average value of the Canadian dollar decreased relative to the US dollar by 9% from 1.16:1 to 1.27:1.

Derivative Gain (Loss), Net

Three months ended ($ Thousands)		March 31, 2016		March 31, 2015
Unrealized derivative gain (loss)	$	(20,860)	$	25,149
Realized derivative gain		911		762
DERIVATIVE GAIN (LOSS), NET	$	(19,949)	$	25,911

Concurrent with the issuance of the US$225.0 million Term Loan in May 2014, Athabasca entered into a three year foreign exchange par forward contract expiring on March 31, 2017 to reduce the Company's exposure to fluctuations in foreign exchange rates on its US dollar denominated long-term debt. During the three months ended March 31, 2016, Athabasca recognized a net derivative loss as the value of the Canadian dollar increased relative to the US dollar. During the three months ended March 31, 2015, Athabasca recognized a net derivative gain as the value of the Canadian dollar decreased relative to the US dollar.

CAPITAL EXPENDITURES

Light Oil Division

The following table summarizes the Light Oil capital expenditures for the three months ended March 31, 2016 and 2015:

Three months ended ($ Thousands)		March 31, 2016		March 31, 2015
Duvernay	$	5,864	$	56,980
Montney		20,220		13,993
Operations and other		4,103		4,279
Land and lease rentals		471		3,989
TOTAL LIGHT OIL CAPITAL EXPENDITURES(1)(2)	$	30,658	$	79,241

(1) During the three months ended March 31, 2016, $8.7 million of Light Oil capital expenditures were classified as assets held for sale relating to the Murphy Transaction.
(2) For the three months March 31, 2016, capital expenditures include $1.6 million in capitalized staff costs (March 31, 2015 - $2.5 million).

During the three months ended March 31, 2016, Athabasca spent $30.7 million in the Light Oil Division. The Company spent $20.2 million in the Montney in the Greater Placid area primarily to complete three and bring on stream four Montney wells that had been drilled in the prior year. Athabasca also completed construction and commissioning of a pipeline that connects the Company's Montney wells in the Greater Placid area to its regional infrastructure at Saxon. The pipeline was operational in the first quarter of 2016.

Athabasca spent $5.9 million on the Duvernay in the Greater Kaybob area, primarily to complete the drilling of a four-well Duvernay pad and bring two Duvernay wells on stream that had been drilled and completed in the prior year.

The Company also spent $4.2 million on optimization, maintenance, project support and lease rentals to support ongoing operations.

Thermal Oil Division

The following table summarizes the Thermal Oil capital expenditures for the three months ended March 31, 2016 and 2015:

Three months ended ($ Thousands)		March 31, 2016		March 31, 2015
Hangingstone Project 1	$	197	$	62,674
Hangingstone Expansion		462		1,823
Other Thermal Oil exploration		257		4,007
TOTAL THERMAL OIL CAPITAL EXPENDITURES(1)	$	916	$	68,504

(1) For the three months ended March 31, 2016, Thermal Oil capital expenditures include $0.4 million in capitalized staff costs (March 31, 2015 - $5.2 million).

There were minimal capital expenditures in the Thermal Oil Division during the first quarter of 2016. During the three months ended March 31, 2015, Athabasca spent $62.7 million on Project 1 primarily to complete the project and commence operations. The Company completed Project 1 construction during the first quarter of 2015, transitioned to operations during the second quarter and the project became ready for use during the third quarter of 2015.

The Company's application for the expansion of Hangingstone by an incremental 70,000 bbl/d has been confirmed as technically complete by the AER and Athabasca anticipates receiving final regulatory approval in 2016. Prior to the sanctioning of any expansion projects at Hangingstone, successful production ramp-up of Project 1 will need to be demonstrated, along with a recovered and stable commodity price environment as well as suitable project funding.

OUTLOOK

In December 2015, Athabasca released its 2016 capital budget of $91 million (gross) with average corporate production guidance of 16,000 - 18,000 boe/d (gross). The following table reflects the Company's initial 2016 budget, adjusted for the Murphy Transaction which is anticipated to close during the second quarter of 2016:

2016 Budget	Original	Revised
CAPITAL(1) ($ MILLIONS)		
Light Oil Division	$ 71	$ 42
Thermal Oil Division	11	11
Capitalized general and administrative	8	8
	$ 91	$ 61
PRODUCTION		
Light Oil production (boe/d)	7,000 - 8,000	4,500 - 5,000
Thermal Oil production (bbl/d)	9,000 - 10,000	9,000 - 10,000
	16,000 - 18,000	13,500 - 15,000

(1) Figures may not add due to rounding.

No additional Light Oil capital has been approved for the second half of 2016. Athabasca is maintaining operational readiness to increase development in both the Montney and Duvernay.

Following the closing of the Murphy Transaction, Athabasca is anticipated to have approximately $880 million of liquidity (including cash, cash equivalents and the promissory note). The Company's liquidity will be further bolstered by the $225.0 million capital carry commitment in the Duvernay. The Company is evaluating alternatives to enhance its capital structure and remains committed to reducing total leverage by $300 to $400 million during 2016.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity risk

The Company's objective in managing liquidity risk is to maintain sufficient available reserves to meet its liquidity requirements at any point. The Company achieves this by managing its capital spending and maintaining sufficient funds for anticipated short-term spending in cash and cash equivalent accounts. Until required, excess cash will be invested in short-term deposits and investments.

Funding

The Company intends to proactively enhance its capital structure by retiring a portion of long-term debt in 2016. Balance sheet strength and flexibility will remain a key priority for Athabasca, particularly in the current operating environment. As at March 31, 2016, Athabasca had liquidity of $627.4 million including cash and cash equivalents of $493.5 million and a promissory note of $133.9 million receivable in the third quarter of 2016. Following the closing of the Murphy Transaction, Athabasca is anticipated to have approximately $880 million of liquidity (including cash, cash equivalents and the promissory note).

It is anticipated that Athabasca's 2016 capital and operating budgets, including continued appraisal and development activities in the Light Oil Division and the ramp-up of Project 1, and any debt repayments will be funded with existing cash and cash equivalents, the remaining promissory note, operating income from the Light Oil and Thermal Oil divisions, proceeds from the Murphy Transaction, the Duvernay capital carry from the Murphy Transaction and available credit. Beyond 2016, the Company may require additional capital to develop its assets and Athabasca believes it will fund its capital programs through some combination of cash and cash equivalents, the Duvernay capital carry from the Murphy Transaction, a reasonable level of debt and other external financing. The Company cannot guarantee the availability of these sources of additional funding and the availability of future funding will depend on, among other things, the current commodity price environment, performance in both the Light Oil Division and Hangingstone, the Company's credit rating at the time and the current state of the equity and debt capital markets.

Indebtedness

The following table summarizes Athabasca's Net Debt as at March 31, 2016 and December 31, 2015:

($ Thousands)		March 31, 2016		December 31 2015
Long-term debt		820,478		838,205
Less:				
Current assets		1,187,838		746,651
Assets held for sale (included in current assets)(1)		(466,159)		—
Current portion of derivative asset (included in current assets)		(41,724)		(5,382)
Accounts payable and accrued liabilities		(66,418)		(54,707)
Current portion of long-term debt		(2,868)		(3,068)
		610,669		683,494
NET DEBT(1)	$	209,809	$	154,711

(1) Upon closing of the Murphy Transaction, Athabasca is anticipated to receive cash proceeds of approximately $250.0 million. The net proceeds are not reflected in the Net Debt measure above.
(2) Refer to "Advisories and Other Guidance" beginning on page 16 for additional information on Non-GAAP Financial Measures.

On November 19, 2012, Athabasca issued Notes in an aggregate principal amount of $550 million. The Notes bear interest at a rate of 7.50% per annum and have a term of five years maturing on November 19, 2017. Interest payments are required semi-annually on May 19 and November 19 of each year.

On May 7, 2014, Athabasca entered into a credit agreement providing for the US$225 million Term Loan, which was fully funded at closing, plus an additional US$50 million committed delayed draw term loan, which is available to the Company up until May 20, 2016, subject to compliance with certain conditions precedent and covenants (collectively the "Term Loans"). The Term Loan bears interest at a rate of LIBOR plus 7.25%, subject to a 1% LIBOR floor. As at March 31, 2016, Athabasca was in compliance with all of the Term Loan covenants.

On May 7, 2014, concurrent with entering into the Term Loans, the Company entered into a $125 million amended and restated credit agreement with a syndicate of financial institutions to replace its previous credit facility. The amended and restated Credit Facility is available on a revolving basis until April 30, 2017. As at March 31, 2016, Athabasca was in compliance with all of the Credit Facility covenants, including its tangible net worth covenant which was amended from a minimum of $2,750 million to $1,700 million.

As at March 31, 2016, no amounts had been drawn under the Credit Facility (December 31, 2015 - $ nil) and Athabasca had $100.5 million in letters of credit secured against the Credit Facility (December 31, 2015 - $7.3 million) primarily relating to financial assurance requirements associated with the Company's long-term pipeline transportation commitments.

The Company's significant outstanding financial liabilities mature as follows: the Notes mature on November 19, 2017; the Term Loan matures on May 7, 2019 or on May 19, 2017 if the Company has not redeemed or refinanced the Notes prior to that date. The delayed draw term loan expires on May 20, 2016 and the Credit Facility matures on April 30, 2017.

Refer to Athabasca's unaudited condensed interim consolidated financial statements for the three months ended March 31, 2016 for additional information regarding the Company's long-term debt and credit facilities.

Commitments and Contingencies

The following table summarizes Athabasca's estimated future minimum commitments as at March 31, 2016 for the following five years and thereafter:

($ Thousands)	2016	2017	2018	2019	2020	Thereafter	Total
Transportation	$ 39,268	$ 53,922	$ 49,015	$ 51,749	$ 51,463	$ 856,200	$ 1,101,617
Repayment of long-term debt(1)(2)	2,145	552,836	2,807	278,990	—	—	836,778
Interest expense on long-term debt(2)	48,900	59,878	23,418	8,178	—	—	140,374
Office leases	1,839	2,452	2,452	2,452	2,452	11,808	23,455
Purchase commitments and other	9,181	—	—	—	—	—	9,181
Drilling rigs	2,082	2,915	—	—	—	—	4,997
TOTAL COMMITMENTS	$ 103,415	$ 672,003	$ 77,692	$ 341,369	$ 53,915	$ 868,008	$ 2,116,402

(1) The Term Loan is required to be repaid on May 19, 2017 if the Company has not redeemed or refinanced the Notes prior to this date.

(2) Estimated future interest and principal repayments relating to the Term Loan have been translated a rate of US$1.00 = C$1.2971 in the table above which is based on the current spot rate as at March 31, 2016.

Excluded from the table above is a commitment for $128.2 million of office leases which were assigned to a third party in December 2013.

Athabasca is responsible for the retirement of its resource assets at the end of their useful lives.

The Company is currently undergoing income tax related audits in the normal course of business. While the final outcome of such audits cannot be predicted with certainty, it is the opinion of management that the resolution of these audits will not have a material impact on the Company's consolidated financial position or results of operations.

The Company may, from time to time, be involved in claims arising in the normal course of business.

Athabasca has entered into indemnity agreements with its directors and officers whereby the Company indemnifies the directors and officers to the fullest extent permitted by law against all personal liability and loss that may arise in service to the Company.

Credit Risk

The maximum exposure to credit risk is represented by the carrying amounts of cash and cash equivalents, accounts receivable, income tax receivable, derivative assets and the promissory note on the consolidated balance sheets. Cash and cash equivalents held by the Company are invested with counterparties meeting credit quality requirements and concentration limits pursuant to an investment policy that is periodically reviewed by the Audit Committee. The policy emphasizes security of assets over investment yield.

As at March 31, 2016 and December 31, 2015 Athabasca's cash and cash equivalents were held with four counterparties. The Company holds investments in term deposits with large reputable financial institutions. The Company's management believes that credit risk associated with these investments is low. At March 31, 2016, the largest institution held 33% of the balances (December 31, 2015 - 32%).

As at March 31, 2016, 54% of the accounts receivable balance relates to the sale of petroleum and natural gas and was substantially collected within 30 days after the end of the period (December 31, 2015 - 40%). Joint interest billings and equipment disposals with partners account for 23% of accounts receivable (December 31, 2015 - 18%). 12% relates to accrued interest on the promissory note (December 31, 2015 - 12%). Additionally, 11% of the accounts receivable balance relates to GST, a cash call receivable and other receivables (December 31, 2015 - 30%). Management believes collection risk on the outstanding accounts receivable as at March 31, 2016 is low given the high credit quality of the Company's material counterparties. No material amounts were past due at March 31, 2016.

As at March 31, 2016, Athabasca holds $137.5 million in a remaining promissory note including the note principal and accrued interest. The promissory note is unconditional and secured by an irrevocable, standby letter of credit issued by HSBC Bank Canada ("HSBC"). Management believes that credit risk associated with this receivable is low as the issuer, Phoenix Energy Holding Ltd., a wholly owned subsidiary of PetroChina International Investment Company Limited, is an investment grade rated corporation, and HSBC is a large reputable financial institution. The first and second promissory notes, which matured on March 2, 2015 and August 28, 2015 respectively, were fully collected on maturity.

Foreign exchange risk

The Company is exposed to foreign exchange risk on its US dollar denominated Term Loan and US dollar forward contract as described below. If the Canadian dollar strengthened by 5% relative to the US dollar, holding all other variables constant, the derivative asset of $41.7 million would decrease by $15.4 million. Long-term debt would decrease by $14.2 million resulting in a net $1.2 million loss. A 5% decrease in the Canadian dollar relative to the US dollar, holding all other variables constant, would increase the derivative asset by $15.4 million and increase long-term debt by $14.2 million resulting in a net $1.2 million gain.

Athabasca is exposed to foreign currency risk on its US dollar denominated Term Loan. In May 2014, Athabasca entered into a US dollar forward contract for US$270.8 million relating to the interest payments and principal repayments on the Term Loan at a rate of US$1.00 = C$1.1211 expiring on March 31, 2017. This contract is accounted for as a derivative instrument and changes in the valuation are recognized in net income (loss) and the associated liability or asset is recognized on the balance sheet.

($ Thousands)		March 31, 2016		December 31, 2015
OPENING DERIVATIVE ASSET	$	62,584	$	12,638
Unrealized derivative gain (loss)		(20,860)		49,946
CLOSING DERIVATIVE ASSET	$	41,724	$	62,584
Presented as:				
Current portion of derivative asset	$	41,724	$	5,382
Long-term portion of derivative asset	$	—	$	57,202

Interest Rate Risk

The Company’s exposure to interest rate fluctuations on interest earned on its floating rate cash balance of $414.4 million (December 31, 2015 - $480.6 million), from a 1.00% change in interest rates, would be approximately $4.1 million for a 12 month period (year ended December 31, 2015 - $4.8 million). The Company is also exposed to interest rate cash flow risk on its floating rate Term Loan. However, given that the Company has a 1.00% LIBOR floor on its Term Loan, a decrease in the rate would have no impact. A 1.00% increase in LIBOR above the existing rate would result in a US$1.4 million ($1.8 million) increase in interest expense for a 12 month period (year ended December 31, 2015 - US$1.4 million ($1.9 million)).

Off Balance Sheet Arrangements

The Company has a number of transportation, office leases, drilling and other purchase commitments reflected in the table above under the heading “Commitments and Contingencies”, which were entered into in the normal course of operations. No asset or liability value has been assigned to these agreements on the Company’s balance sheet. Payments pursuant to these leases are recognized in the consolidated financial statements as incurred. Provisions relating to onerous office lease contracts have been recognized on the Company's consolidated balance sheet and are excluded from the Commitments and Contingencies schedule above. The Company has no other off balance sheet arrangements.

Equity Instruments

During the three months ended March 31, 2016, the Company issued 0.4 million common shares. Issuances of Athabasca’s common shares in 2016 relate to 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 April 30, 2016	
Common shares issued and outstanding	405,386,280
Convertible securities:	
Stock options	8,573,319
Restricted share units (2010 RSU Plan)	5,445,604
Restricted share units (2015 RSU Plan)	4,714,093
Performance share units	1,358,900
Deferred share units	697,366

For additional information regarding these compensation plans, refer to the Company's consolidated financial statements of the Company for the year ended December 31, 2015.

SUMMARY OF QUARTERLY RESULTS

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

	2016	2015				2014		
($ Thousands, Except Share and Per Barrel Amounts)	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	33.45	42.18	46.43	57.94	48.63	93.00	97.19	102.96
Western Canadian Select (C$/bbl)	26.30	36.86	43.29	71.24	60.35	83.03	105.84	112.31
Edmonton Par (C$/bbl)	40.67	52.85	56.17	67.63	51.79	94.49	97.03	106.67
Edmonton Condensate (C5+) (C$/bbl)	46.32	54.52	56.94	69.81	55.42	100.42	99.87	112.49
NYMEX Henry Hub (US$/MMBtu)	2.09	2.27	2.80	2.64	2.98	4.39	4.07	4.59
AECO (C$/GJ)	1.74	2.33	2.75	2.53	2.61	4.25	3.82	4.71
Foreign exchange (CAD : USD)	1.37	1.34	1.31	1.23	1.24	1.16	1.12	1.09
LIGHT OIL DIVISION								
Sales volumes (boe/d)	6,319	5,873	5,145	5,459	5,877	6,035	6,381	5,768
Realized price ($/boe)	21.73	27.39	31.34	34.43	29.35	44.66	56.90	65.97
Revenues[(2)] ($)	12,440	17,624	14,043	17,666	13,981	21,757	29,892	32,587
Light Oil Operating Income[(1)] ($)	4,908	10,551	6,096	10,689	6,578	12,431	21,154	24,207
Light Oil Operating Netback[(1)] ($/boe)	8.53	19.50	12.88	21.51	12.46	22.38	36.03	46.12
Capital expenditures ($)	30,658	50,921	31,465	14,959	79,241	87,870	19,772	14,847
THERMAL OIL DIVISION								
Bitumen production (bbl/d)[(3)(4)]	7,029	5,708	2,105	—	—	—	—	—
Sales volumes (bbl/d)[(3)(4)]	7,176	4,096	1,792	—	—	—	—	—
Realized bitumen price ($/bbl)	7.27	21.23	17.54	—	—	—	—	—
Revenues[(2)] ($)	21,076	15,033	6,145	—	—	—	—	—
Thermal Oil Operating Loss[(1)(4)] ($)	(23,074)	(18,166)	(12,146)	—	—	—	—	—
Thermal Oil Operating Netback[(1)(4)] ($/bbl)	(35.34)	(48.22)	(73.67)	—	—	—	—	—
Capital expenditures	916	2,257	9,366	33,118	68,504	78,876	89,455	90,556
OPERATING RESULTS								
Cash Flow from Operations ($)	(38,017)	(54,496)	(17,933)	8,576	(2,610)	(8,883)	30,371	(18,641)
Funds Flow from Operations[(1)] ($)	(39,982)	(30,141)	(24,223)	5,085	3,162	(2,520)	7,203	5,016
Net income (loss) ($)	(65,129)	(604,375)	(38,241)	(29,044)	(25,112)	(129,507)	(19,939)	(56,766)
Net income (loss) per share - basic ($)	(0.16)	(1.50)	(0.09)	(0.07)	(0.06)	(0.32)	(0.05)	(0.14)
Net income (loss) per share - diluted ($)	(0.16)	(1.50)	(0.09)	(0.07)	(0.06)	(0.32)	(0.05)	(0.14)
BALANCE SHEET ITEMS								
Cash and cash equivalents ($)	493,510	559,487	671	582,396	570,290	531,475	722,747	182,499
Short-term investments ($)	—	—	—	—	92,873	47,618	—	—
Promissory notes - short-term ($)	133,892	133,892	133,892	150,000	150,000	450,000	450,000	—
Promissory notes - long-term ($)	—	—	—	133,892	133,892	133,892	133,892	—
Assets held for sale ($)	466,159	—	—	—	—	—	—	1,232,279
Total assets ($)	3,394,367	3,462,442	4,160,344	4,173,704	4,244,486	4,297,803	4,413,935	4,459,943
Long-term debt ($)	820,478	838,205	827,773	807,167	810,758	786,649	777,528	764,788
Net Debt[(1)] ($)	209,809	154,711	55,433	109,713	68,005	(123,625)	(305,161)	(555,789)
Shareholders' equity ($)	2,419,651	2,482,140	3,085,499	3,119,224	3,141,453	3,164,186	3,289,083	3,301,011

(1) Refer to "Advisories and Other Guidance" beginning on page 16 for additional information on Non-GAAP financial measures.
(2) Consists of petroleum and natural gas sales and midstream revenues, net of royalties. Excludes interest income and other.
(3) For the three months ended September 30, 2015, Thermal Oil bitumen production and sales volumes on a bbl/d basis represent all Hangingstone sales and production volumes (including capitalized volumes) for the quarter averaged over 92 days.
(4) Athabasca capitalized initial operating results of Hangingstone Project 1 until the project was deemed ready for use in the manner intended by management on August 1, 2015. Operating results and sales volumes prior to August 1, 2015 have been capitalized and excluded from the calculation of the Thermal Oil Operating Loss and Netback.

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.

SUBSEQUENT EVENT

On May 5, 2016, Project 1 was shut down due to the regional Fort McMurray wildfires. The decision to shut down the well sites and central facility was due to elevated safety risks from the fire's proximity to Project 1. At this time, there is no damage to the facility, field pipelines or well sites. Timing for a restart of operations will be contingent on containment of the regional fires and ensuring safe operating conditions. Athabasca maintains property and business insurance that is customary for companies of similar size and with similar types of business and operations. The Company cannot predict the amount of any financial loss that may result from this event at this time, nor can it provide assurances that the full amount of any financial loss will be recovered by insurance.

Operating results of the Thermal Oil division are comprised solely of Project 1. For details of the operating results refer to *Note 9 - Segmented Information* of the unaudited condensed interim consolidated financial statements for the three months ended March 31, 2016.

ACCOUNTING POLICIES AND ESTIMATES

During the three months ended March 31, 2016, 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. Refer to the December 31, 2015 audited consolidated financial statements of the Company for further guidance regarding Athabasca's accounting policies and use of estimates.

ADVISORIES AND OTHER GUIDANCE

Non-GAAP Financial Measures

The "Light Oil Operating Netback", "Light Oil Operating Income", "Thermal Oil Operating Netback", "Thermal Oil Operating Income", "Funds Flow from Operations" and "Net Debt" 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 Net Debt measure in this MD&A (including the comparatives thereto) is calculated by subtracting the current assets (excluding assets held for sale and the current portion of derivative assets) less accounts payable and accrued liabilities and the current portion of long-term debt from Company's long-term debt. The table on page 12 reconciles the Net Debt non-GAAP financial measure to the Company's consolidated balance sheet. The Net Debt measure is not intended to represent other measures of financial position on the Company's balance sheet that are calculated in accordance with IFRS. The Net Debt financial measure allows management and others to evaluate the Company's funding position and utilization of debt within its capital structure.

The following table reconciles cash flow from operating activities in the consolidated financial statements for the three months ended March 31, 2016 and 2015 to Funds Flow from Operations:

Three months ended ($ Thousands)	March 31, 2016	March 31, 2015
Cash flow from operating activities	$ (38,017)	$ (2,610)
Restructuring and other charges, excluding change in long-term portion of office lease provision	—	13,520
Changes in non-cash working capital	(3,772)	(9,855)
Settlement of provisions	1,448	2,107
Other items	$ 359	—
FUNDS FLOW FROM OPERATIONS	$ (39,982)	$ 3,162

Funds Flow from Operations is not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS. The Funds Flow from Operations 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 operating related activities. Funds Flow from Operations per share (basic and diluted) are calculated as Funds Flow from Operations divided by the number of weighted average basic and diluted shares outstanding.

The Light Oil Operating Income and Light Oil Operating Netback measures in this MD&A (including the comparatives thereto) are calculated by subtracting royalties and operating and transportation expenses from petroleum and natural gas sales and midstream revenues received. The Light Oil Operating Netback measure is presented on a per boe basis. The Light Oil Operating Income and the Operating Netback (per boe) measures allow management and others to evaluate the production results from the Company's Light Oil assets. The table on page 6 reconciles Light Oil Operating Income to *Note 9 - Segmented Information* in the unaudited condensed interim consolidated financial statements for the three months ended March 31, 2016.

The Thermal Oil Operating Income and Thermal Oil Operating Netback measures in this MD&A (including the comparatives thereto) are calculated by subtracting cost of diluent blending, royalties, operating expenses and transportation expenses from blended bitumen sales received. The Thermal Oil Operating Netback measure is presented on a per bbl basis. The Thermal Oil Operating Income and the Thermal Oil Operating Netback (per bbl) measures allow management and others to evaluate the production results from the Company's Thermal Oil assets. The table on page 7 reconciles Thermal Oil Operating Income to *Note 9 - Segmented Information* in the unaudited condensed interim consolidated financial statements for the three months ended March 31, 2016.

Risk Factors

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

- risks associated with regional fires and other events of force majeure;
- 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;
- the substantial capital requirements of Athabasca's projects and the ability to obtain financing for Athabasca's capital requirements;
- failure to realize anticipated benefits of acquisitions or divestments;
- risks related to hydraulic fracturing;
- 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;
- insurance risks;
- 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, GHG regulations and potential Canadian and U.S. climate change legislation;
- risks related to the finalization and closing of the Murphy Transaction;
- dependence upon Murphy as a working interest participant in its Light Oil assets and as operator of the Kaybob assets;
- risks related to the Amended Credit Facility, Term Loans and the Senior Secured Notes;
- Geopolitical risks;
- uncertainties inherent in estimating quantities of reserves and resources;
- 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;
- risks related to gathering and processing facilities and pipeline systems;
- availability of drilling and related equipment and limitations on access to Athabasca's assets;
- failure to accurately estimate abandonment and reclamation costs;
- the potential for management estimates and assumptions to be inaccurate;
- reliance on third party infrastructure;
- seasonality;
- hedging risks;
- risks associated with establishing and maintaining systems of internal controls;
- 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.

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 timing of the ramp-up of production and of achieving plateau production from Project 1; the Company's expectation that Netbacks will improve as production increases; the timing of drilling, completion and tie-in operations in the Company’s Light Oil division; the benefits expected to be realized from placing the Company’s Light Oil division Duvernay wells on a soak period; the Company’s expected production from the Light Oil and Thermal Oil divisions during 2016; the expected timing of the Company’s Light Oil division wells coming on-stream; the benefits expected to be realized from the use of recovery technologies in the Company’s Light Oil division, including multi-stage, energized hybrid completion technology; the anticipation of lower service costs in the second half of 2016; the Company’s expected flexibility in its pace of development; the Company’s drilling plans, in particular, with respect to the Duvernay and Montney formations; the timing of the Company’s well completion operations; expected timing for completion of the pipeline linking the Placid area to the existing Kaybob transporation infrastructure; the Company’s plans for, and results of, exploration and development activities; the finalization and closing of the Murphy Transaction; the Company’s estimated future commitments; the receipt of proceeds from the remaining promissory note; the Company’s expected funding-in-place at the end of 2016; the Company’s business and financing plans; the Company’s business and financing strategies; expectations regarding the 2016 capital budget; and the future allocation of capital.

With respect to forward-looking information contained in this MD&A, assumptions have been made regarding, among other things: the regulatory framework governing royalties, taxes and environmental matters in the jurisdiction in which the Company conducts and will conduct business; 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; geological and engineering estimates in respect of the Company’s reserves and resources; recoverability of reserves and resources and 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 dated March 10, 2016, 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; risks associated with regional fires and other events of force majeure; 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, GHG regulations and potential Canadian and U.S. climate change legislation; risks related to the Murphy Transaction, including the risk that the parties are unable to meet the conditions precedent to closing the Murphy Transaction or that the Murphy Transaction does not close on the timeline anticipated or at all, dependence on Murphy as the operator of the Kaybob assets, dependence on Murphy as the Company’s joint venture participant in the Company’s Kaybob and Placid assets and dependence on Murphy’s continued ability to pay the Kaybob carry commitment; risks related to the Amended Credit Facility, Term Loans and the Senior Secured 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; hedging risks; 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 reports of GLJ Petroleum Consultants Ltd. ("GLJ") and DeGolyer and MacNaughton Canada Limited ("D&M") evaluating Athabasca's Proved Reserves, Probable Reserves and Contingent Resources as at December 31, 2015 (which are respectively referred to herein as the "GLJ Report" and the "D&M" 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

Both the GLJ Report and the D&M Report were 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, 2015. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties due to the effect of aggregation. The reserves estimates are estimates only, the actual reserves may be greater or less than those calculated and variances could be material. Reserves figures described herein have been rounded to the nearest MMbbl or MMboe. The resource estimates are estimates only. The actual Contingent Resources may be greater than or less than the estimates provided and variances could be material. There is no certainty that it will be commercially viable to produce any portion of the resources. 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 GLJ in the GLJ Report and by D&M in the D&M Report, please refer to the Company's AIF and the Material Change Report that are available on SEDAR at www.sedar.com.

Drilling Locations

The 1,500 Duvernay drilling locations referenced on page 1 of this MD&A includes: 15 proved undeveloped or non-producing locations, 27 probable undeveloped locations for a total of 42 undeveloped booked locations with the balance being unbooked locations. The 165 Montney drilling locations referenced on page 1 of this MD&A includes: 24 probable undeveloped locations, all of which have a proven component, 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 GLJ as of December 31, 2015 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

"Company Interest" means the Company's consolidated total working interest share before deduction of royalties and without excluding royalty interests.

"**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, 2015, the Company is reporting Contingent Resources on a risked and unrisked basis located in its: Hangingstone asset area in the Development Pending project maturity sub-class and located in its Hangingstone, Dover West Sands and Birch asset areas for Development On Hold and Development Unclarified project maturity sub-classes.

"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.

"**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**" 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.
AER	Alberta Energy Regulator
bbl	barrel
bbl/d	barrels per day
boe(1)	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
C$	Canadian Dollars
COGE	Canadian Oil and Gas Evaluation
E&E	Exploration and evaluation assets
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
PP&E	Property, plant and equipment
SAGD	steam assisted gravity drainage
SOR	Steam to oil ratio
TAGD	thermal assisted gravity drainage
TCPL	TransCanada Pipeline
US$	United states Dollars

(1) Boe may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one bbl of oil (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.