ATHABASCA OIL CORPORATION

Management's Discussion and Analysis

Q2 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 July 27, 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 and six months ended June 30, 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 19 of this MD&A. See "Reserves and Resource information" on page 22 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 23 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 a 70% operated working interest in 60,000 gross acres of Montney lands within the Greater Placid area, of which 25,000 acres are considered commercially prospective, with a potential inventory of more than 165(1) gross drilling locations. Athabasca also has a 30% non-operated interest in over 200,000 gross acres of commercially prospective Duvernay lands in the Greater Kaybob area at various stages of delineation and development with a potential inventory of approximately 1,500(1) gross drilling locations. Development to date has resulted in the booking of approximately 65 MMboe of Proved plus Probable Reserves (100%) attributable to the assets in Athabasca's Light Oil Division as of December 31, 2015(2). During the six months ended June 30, 2016, the Light Oil Division produced 6,031 boe/d.

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 six months ended June 30, 2016, the Thermal Oil Division produced 6,193 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 19 for additional information regarding the Company's drilling locations.
(2) Based on the reports of Athabasca's independent reserve evaluators effective December 31, 2015. The Murphy Transaction (discussed below) was completed on May 13, 2016 and resulted in the sale of approximately 38 MMboe of Proved plus Probable Reserves from the Light Oil Division based on Management's best estimate. Refer to page 19 and the AIF for additional important information about the Company's Reserves and Contingent Resources.

SELECTED FINANCIAL INFORMATION

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

($ Thousands, except volume, boe and share amounts)	Three months ended June 30, 2016	Three months ended June 30, 2015	Six months ended June 30, 2016	Six months ended June 30, 2015
CONSOLIDATED PRODUCTION				
Petroleum and natural gas volumes (boe/d)	11,101	5,459	12,224	5,667
LIGHT OIL DIVISION				
Petroleum and natural gas sales volumes (boe/d)	5,743	5,459	6,031	5,667
Light Oil Operating Income[(1)]	$ 7,215	$ 10,689	$ 12,123	$ 17,281
Light Oil Operating Netback[(1)] ($/boe)	$ 13.80	$ 21.51	$ 11.03	$ 16.84
Capital expenditures	$ 5,518	$ 14,959	$ 36,176	$ 94,200
Recovery of capital-carry through capital expenditures	$ (1,474)	—	$ (1,474)	—
THERMAL OIL DIVISION				
Bitumen production (bbl/d)	5,358	—	6,193	—
Bitumen sales volumes (bbl/d)	4,463	—	5,820	—
Thermal Oil Operating Loss[(1)(2)]	$ (11,915)	$ —	$ (34,990)	$ —
Thermal Oil Operating Netback ($/bbl)[(1)(2)]	$ (29.33)	$ —	$ (33.03)	$ —
Capital expenditures	$ 2,187	$ 33,118	$ 3,094	$ 101,685
CASH FLOW AND FUNDS FLOW				
Cash flow from operating activities	5,759	8,576	(32,268)	5,922
Cash flow from operating activities per share (basic and diluted)	$ 0.01	$ 0.02	$ (0.08)	$ 0.01
Funds Flow from Operations[(1)]	$ (27,304)	$ 5,085	$ (67,420)	$ 8,201
Funds Flow from Operations per share (basic and diluted)[(1)]	$ (0.07)	$ 0.01	$ (0.17)	$ 0.02
NET LOSS AND COMPREHENSIVE LOSS				
Net loss and comprehensive loss	$ (59,169)	$ (29,044)	$ (124,298)	$ (54,156)
Net loss and comprehensive loss per share (basic and diluted)	$ (0.15)	$ (0.07)	$ (0.31)	$ (0.13)
SHARES OUTSTANDING				
Weighted average shares outstanding (basic and diluted)	405,222,515	402,981,471	404,964,704	402,698,520
FINANCING AND DIVESTITURES				
Cash proceeds from sales of assets	$ 392,175	$ —	$ 392,338	$ —
Promissory note proceeds	$ —	$ —	$ —	$ 300,000
Repayment of long-term debt	$ (284,722)	$ (626)	$ (285,441)	$ (1,336)
Receipt of derivative proceeds upon repayment of long-term debt	$ 40,956	$ —	$ 40,956	$ —

(1) Refer to “Advisories and Other Guidance” beginning on page 19 for additional information on Non-GAAP Financial Measures.
(2) 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.

As at ($ Thousands)	June 30, 2016	December 31, 2015
BALANCE SHEET ITEMS		
Cash and cash equivalents	$ 447,282	$ 559,487
Short-term investments	$ 25,533	$ —
Promissory note	$ 133,892	$ 133,892
Restricted cash	$ 101,652	$ —
Long-term receivables and other[(1)]	$ 181,443	$ 3,044
Total assets	$ 3,028,938	$ 3,462,442
Long-term debt	$ 544,042	$ 838,205
Net debt[(2)]	$ (90,834)	$ 154,711
Shareholders’ equity	$ 2,363,396	$ 2,482,140

(1) Long-term receivables and other primarily consists of the long-term portion of the discounted capital-carry receivable of $181.4 million ($206.7 million undiscounted).
(2) Refer to “Advisories and Other Guidance” beginning on page 19 for additional information on Non-GAAP Financial Measures.

HIGHLIGHTS FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2016

Corporate

- On May 13, 2016, Athabasca entered into a strategic joint venture with Murphy Oil Company Ltd. ("Murphy") to develop the Montney and Duvernay formations in the Greater Kaybob and Greater Placid areas. As part of the transaction, Athabasca sold an operated 70% interest in its Greater Kaybob area assets and a non-operated 30% interest in its Greater Placid area assets for gross proceeds of $486.5 million, consisting of $267.5 million in cash and a $219.0 million (undiscounted) capital-carry receivable 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 "Murphy Transaction"). 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.
- On June 17, 2016, Athabasca sold a Contingent Bitumen Royalty on its Thermal Oil assets to Burgess Energy Holdings L.L.C. ("Burgess") for gross cash proceeds of $128.5 million. Athabasca will pay Burgess a sliding-scale royalty of 0% - 6% based on Athabasca's realized bitumen price (C$), which is determined net of diluent, transportation and storage costs. At Hangingstone, oil prices of approximately US$75/bbl WTI would need to be reached before the first royalty tier of 1% is triggered(1).
- On June 17, 2016, Athabasca repaid its US$225.0 million senior secured first lien term loan (the "Term Loan") at par for C$286.8 million. Concurrent with the repayment of the Term Loan, Athabasca also unwound its US dollar forward contract associated with the Term Loan for net proceeds of C$41.0 million. The Company also reduced its $125.0 million revolving credit facility (the "Credit Facility") to $44.5 million (undrawn) and established a new $110.0 million bilateral cash collateralized letter of credit facility ("Letter of Credit Facility") for its transportation commitments.
- As at June 30, 2016, Athabasca had Liquidity(2) of $606.7 million consisting of cash and cash equivalents of $447.3 million, short-term investments of $25.5 million and a promissory note for $133.9 million due in the third quarter of 2016. The Company also had a $217.6 million capital-carry receivable (undiscounted) remaining from Murphy that will be used to fund Light Oil development in the Greater Kaybob area.
- During the three and six months ended June 30, 2016, the Company's corporate production averaged 11,101 boe/d and 12,224 boe/d, compared to 5,459 boe/d and 5,667 boe/d during the same periods in the prior year. The net increases in production were primarily due to the ramp up of production at Hangingstone Project 1 which commenced during the third quarter of 2015.

Light Oil Division

- For the three and six months ended June 30, 2016, Athabasca produced 5,743 boe/d (49% liquids) and 6,031 boe/d (50% liquids), respectively, in the Light Oil Division, compared to 5,459 boe/d (48% liquids) and 5,667 boe/d (48% liquids) during the same periods in the prior year. The increases in production were primarily due to new wells brought on stream during the fourth quarter of 2015 and the first quarter of 2016, partially offset by lower production from the sale of Light Oil joint venture assets to Murphy on May 13, 2016.
- During the three months ended June 30, 2016, Athabasca's Light Oil Operating Netback(2) was $13.80/boe, compared to $21.51/boe during the same period in the prior year. During the six months ended June 30, 2016, the Company's Light Oil Operating Netback(2) was $11.03/boe, compared to $16.84/boe during the same period in the prior year. The decreases in the Light Oil Operating Netback(2) were primarily due to lower underlying commodity prices.
- Athabasca spent $36.2 million on capital projects in the Light Oil Division during the six months ended June 30, 2016. In the Greater Placid area, Athabasca brought on stream a four well Montney pad that had been drilled in the prior year. Additionally, 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 June 30, 2016, Athabasca's bitumen production averaged 5,358 bbl/d in the Thermal Oil Division, a 24% decrease compared to 7,029 bbl/d during the first quarter of 2016. The decrease was primarily due to a 19-day shutdown of Project 1 in May as a result of the regional Fort McMurray wildfires. Athabasca resumed operations at Project 1 near the end of May. The fires caused no damage to the facility, field pipelines or well sites. Athabasca exited the second quarter of 2016 with monthly average production of 7,831 bbl/d. Project 1 continues to ramp-up and Athabasca anticipates exiting the fourth quarter of 2016 with production nearing the facility nameplate of 12,000 bbl/d.

(1) WTI based on a 0.8 US$/C$ foreign exchange assumption and US$15/bbl differential between WCS and WTI. Royalties are calculated and payable on a monthly basis.
(2) Refer to "Advisories and Other Guidance" beginning on page 19 for additional information on Non-GAAP Financial Measures.

- The Thermal Oil Operating Netback for the three months ended June 30, 2016 was $(29.33)/bbl, a 17% improvement compared to $(35.34)/bbl/d during the first quarter of 2016. The improvement in the Thermal Oil Operating Netback was primarily due to higher underlying market commodity prices for bitumen during the second quarter of 2016, partially offset by lower production volumes due to the Fort McMurray wildfires. Compared to the fourth quarter of 2015, the Thermal Oil Operating Netback improved by 39% primarily due to higher production volumes and improved market commodity prices for bitumen during the second quarter of 2016.

SALE OF ASSETS

Sale of Light Oil assets

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 sold an operated 70% interest in its Greater Kaybob area assets and a non-operated 30% interest in its Greater Placid area assets for gross proceeds of $486.5 million.

The Murphy Transaction was completed on May 13, 2016. At the date of closing, Athabasca received $267.5 million in cash, including purchase price adjustments from the January 1, 2016 effective date. Additional consideration of approximately $219.0 million (undiscounted) in the form of a capital-carry in the Greater Kaybob area was recognized by Athabasca whereby Murphy will fund 75% of Athabasca's share of development capital up to a maximum five year period. The carry supports approximately $1 billion of Duvernay investment of which Athabasca’s financial exposure is limited to $75 million to retain its 30% working interest. The following table summarizes the net proceeds from the sale of assets to Murphy:

As at		May 13, 2016
Cash proceeds	$	267,479
Greater Kaybob capital-carry receivable (undiscounted)		219,038
Gross proceeds from sale of assets		486,517
Discount applied to Greater Kaybob capital-carry receivable[(1)]		(30,390)
Transaction costs and other		(3,608)
Net proceeds from sale of assets to Murphy	$	452,519

(1) The discount applied to the capital-carry reflects the time value of money of the receivable which is anticipated to be collected within five years.

Sale of Contingent Bitumen Royalty

On June 17, 2016, Athabasca sold a Contingent Bitumen Royalty on each of its Thermal Oil assets to Burgess Energy Holdings L.L.C. ("Burgess") for aggregate gross cash proceeds of $128.5 million. Athabasca will pay Burgess a sliding-scale royalty ranging from 0% - 6% based on Athabasca’s realized bitumen price for each Thermal Oil asset. The realized bitumen price for each asset is calculated as the blended bitumen sales price received less the costs of diluent, transportation, storage and marketing costs. The following table summarizes the Contingent Bitumen Royalty rates applicable at different realized bitumen price ranges:

Hangingstone Realized Bitumen Price ($/bbl)	Royalty rate	Other Thermal Oil exploration areas [(1)] Realized Bitumen Price ($/bbl)	Royalty rate
Below $50/bbl	--	Below $60/bbl	--
$50/bbl to $69.99/bbl	1%	$60/bbl to $79.99/bbl	1%
$70/bbl to $89.99/bbl	2%	$80/bbl to $99.99/bbl	2%
$90/bbl to $109.99/bbl	3%	$100/bbl to $119.99/bbl	3%
$110/bbl to $129.99/bbl	4%	$120/bbl to $139.99/bbl	4%
$130/bbl to $149.99/bbl	5%	$140/bbl to $159.99/bbl	5%
$150/bbl and above	6%	$160/bbl and above	6%

(1) Other Thermal Oil exploration areas consists of Birch, Dover West, and Grosmont.

The Contingent Bitumen 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 Hangingstone Expansion phases or other future Thermal Oil exploration projects. Oil prices would have to reach approximately US$75/bbl WTI (at nameplate capacity of 12,000 bbl/d) before the first 1% Contingent Bitumen Royalty is triggered[(1)]. At this pricing level, Project 1 is estimated to have an annual operating netback of approximately $120 million (net of $2 million royalty). There are no associated commitments to develop future expansions or projects.

(1) WTI based on a 0.8 US$/C$ foreign exchange assumption and US$15/bbl differential between WCS and WTI. Royalties are calculated and payable on a monthly basis.

RESULTS OF OPERATIONS

Business Environment

The following table summarizes the key commodity price benchmarks for the three and six months ended June 30, 2016 and 2015:

Monthly average	Three months ended June 30, 2016	Three months ended June 30, 2015	Change	Six months ended June 30, 2016	Six months ended June 30, 2015	Change
Crude oil:						
West Texas Intermediate (WTI) (US$/bbl)	$ 45.59	$ 57.94	(21)%	$ 39.52	$ 53.29	(26)%
West Texas Intermediate (WTI) (C$/bbl)	$ 58.81	$ 71.27	(17)%	$ 52.56	$ 66.08	(20)%
Western Canadian Select (WCS) (C$/bbl)	$ 41.62	$ 56.98	(27)%	$ 33.97	$ 49.55	(31)%
Edmonton Par (C$/bbl)	$ 54.78	$ 67.63	(19)%	$ 47.79	$ 59.71	(20)%
Edmonton Condensate (C5+) (C$/bbl)	$ 56.80	$ 69.81	(19)%	$ 52.03	$ 62.61	(17)%
Differential:						
WTI vs. WCS (US$/bbl)	$ (13.30)	$ (11.59)	(15)%	$ (13.77)	$ (13.16)	(5)%
WTI vs. WCS (C$/bbl)	$ (17.19)	$ (14.29)	(20)%	$ (18.59)	$ (16.53)	(12)%
Natural gas:						
NYMEX Henry Hub (US$/MMBtu)	$ 1.95	$ 2.64	(26)%	$ 2.02	$ 2.81	(28)%
AECO (C$/GJ)	$ 1.32	$ 2.52	(48)%	$ 1.52	$ 2.56	(41)%
Foreign exchange:						
USD : CAD	1.29	1.23	5 %	1.33	1.24	7 %

The price of WTI for crude oil sales at Cushing, Oklahoma is the primary benchmark for crude oil pricing 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, the foreign exchange rate, transportation costs and quality differentials. During the three and six months ended June 30, 2016, the WTI price declined by 21% and 26%, respectively, compared to the same periods in the prior year primarily due to continuing global over-supply of petroleum production.

During the three and six months ended June 30, 2016, the value of the Canadian dollar declined relative to the US dollar by 5% and 7%, respectively, compared to the same periods 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 WCS price at Hardisty, Alberta is the primary benchmark for Athabasca's blended bitumen sales. The WCS price trades at a wider differential to the WTI price compared to lighter crude oil products. Compared to the same periods in the prior year, the WCS price declined by 27% and 31%, respectively, during the three and six months ended June 30, 2016.

The Edmonton Par price is the primary benchmark for crude oil sales in the Company's Light Oil Division. For the three and six months ended June 30, 2016, the average Edmonton Par price declined by 19% and 20%, respectively, compared to the same period in the prior year.

The Edmonton Condensate (C5+) price is the primary benchmark for 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 utilizes in the blending process at Project 1 in order to deliver produced bitumen to the market. For the three and six months ended June 30, 2016, the average Edmonton Condensate (C5+) price declined by 19% and 17%, respectively, compared to the same periods in the prior year.

During the three months and six months ended June 30, 2016, the AECO price declined by 48% and 41%, respectively, compared to the same periods in the prior year. 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 three quarters 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 average NYMEX gas price became the primary benchmark for natural gas sales in the Light Oil Division. For the three and six months ended June 30, 2016, the average NYMEX price declined by 26% and 28%.

Athabasca typically realizes lower prices for its oil and gas sales compared to benchmark prices as a result of transportation costs, discounts applied 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 and six months ended June 30, 2016 and 2015:

($ Thousands, except bbl, Mcf and boe amounts)	Three months ended June 30, 2016	Three months ended June 30, 2015	Six months ended June 30, 2016	Six months ended June 30, 2015
SALES VOLUMES				
Oil (bbl/d)	2,431	1,997	2,480	2,151
Natural gas (Mcf/d)	17,430	17,038	18,212	17,579
Natural gas liquids (bbl/d)	407	622	516	586
Total (boe/d)	5,743	5,459	6,031	5,667
Consisting of:				
Greater Placid area (boe/d)	2,960	1,026	1,827	1,012
% liquids	51%	47%	51%	50%
Greater Kaybob area (boe/d)	2,783	4,433	4,204	4,655
% liquids	47%	48%	51%	48%
REALIZED PRICES				
Oil ($/bbl)	$ 48.49	$ 59.68	$ 42.55	$ 52.79
Natural gas ($/Mcf)	1.61	2.85	1.63	2.82
Natural gas liquids ($/bbl)	21.55	32.51	20.86	29.21
Realized price ($/boe)	26.93	34.43	24.20	31.81
Royalties ($/boe)	(0.92)	0.45	(0.94)	(1.60)
Operating and transportation expenses(1) ($/boe)	(12.21)	(13.37)	(12.23)	(13.37)
LIGHT OIL OPERATING NETBACK(2) ($/boe)	$ 13.80	$ 21.51	$ 11.03	$ 16.84

(1) For the three and six months ended June 30, 2016, operating and transportation expenses include midstream revenues of $0.64/boe and $0.76/boe, respectively (June 30, 2015 - $0.68, $0.65).

(2) Refer to "Advisories and Other Guidance" beginning on page 19 for additional information on Non-GAAP Financial Measures.

($ Thousands)	Three months ended June 30, 2016	Three months ended June 30, 2015	Six months ended June 30, 2016	Six months ended June 30, 2015
Petroleum and natural gas sales	$ 14,074	$ 17,105	$ 26,566	$ 32,630
Midstream revenue	341	338	838	668
Royalties	(479)	223	(1,028)	(1,637)
Operating and transportation expenses	(6,721)	(6,977)	(14,253)	(14,380)
LIGHT OIL OPERATING INCOME(1)	$ 7,215	$ 10,689	$ 12,123	$ 17,281

(1) Refer to "Advisories and Other Guidance" beginning on page 19 for additional information on Non-GAAP Financial Measures.

During the three and six months ended June 30, 2016, Athabasca's Light Oil production increased by 5% and 6% compared to the same periods in the prior year to 5,743 boe/d and 6,031 boe/d, respectively. The increases in production were primarily due to four Duvernay wells being brought on stream in the fourth quarter of 2015 and six wells coming on stream in the first quarter of 2016 (four Montney, two Duvernay). The increases were partially offset by natural production declines and lower production from the sale of the Light Oil joint venture assets to Murphy on May 13, 2016.

Realized prices decreased by 22% and 24% during the three and six months ended June 30, 2016 to $26.93/boe and $24.20/boe, respectively, compared to the same periods 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 three months ended June 30, 2016 were $0.5 million (3% of revenue) compared to a royalty recovery of $0.2 million during the same period in the prior year. For the six months ended June 30, 2016, Athabasca incurred royalty expenses of $1.0 million (4% of gross revenue) compared to $1.6 million (5% of gross revenue) during the same period in 2015. Declines in royalty expenses were primarily due to the impact of lower market commodity prices on the crown royalty rates. The royalty recovery of $0.2 million during the second quarter of 2015 was a result of gas cost allowance adjustments received.

Compared to the same periods in the prior year, operating and transportation expenses decreased from $13.37/boe to $12.21/boe during the three months ended June 30, 2016, and from $13.37 boe/d to $12.23 boe/d during the six months ended June 30, 2016. The declines in operating and transportation expenses per boe were 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 and six months ended June 30, 2016 and 2015:

	Three months ended June 30,		Six months ended June 30,	
($ Thousands)	2016	2015	2016	2015
Light Oil Operating Income[1]	$ 7,215	$ 10,689	$ 12,123	$ 17,281
Depletion of oil and gas assets	(9,593)	(15,081)	(19,965)	(31,344)
Depreciation of infrastructure assets	(341)	(656)	(797)	(1,780)
Loss on sale of assets	(5,546)	—	(5,585)	—
Exploration expense and other	(58)	(244)	—	(282)
LIGHT OIL SEGMENT LOSS	$ (8,323)	$ (5,292)	$ (14,224)	$ (16,125)

(1) Refer to "Advisories and Other Guidance" beginning on page 19 for additional information on Non-GAAP Financial Measures.

Depletion of oil and gas assets declined by $5.5 million and $11.4 million during the three and six months ended June 30, 2016 compared to the same periods in the prior year, primarily due to lower depletion rates resulting from reserve additions in the Light Oil Division and 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 declines were partially offset by higher production volumes during the first and second quarters of 2016. 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.

During the three and six months ended June 30, 2016, Athabasca recognized a loss of $5.6 million primarily related to closing adjustments and transaction costs associated with the Murphy Transaction.

Thermal Oil Division

Operating results

The following tables summarize the Thermal Oil operating results for the three and six months ended June 30, 2016 and 2015:

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	2016	2015
VOLUMES				
Bitumen production (bbl/d)	5,358	—	6,193	—
Bitumen sales (bbl/d)	4,463	—	5,820	—
Blended bitumen sales (bbl/d)	6,359	—	8,267	—
REALIZED PRICES				
Blended bitumen sales ($/bbl)	$ 33.70		$ 26.99	
Bitumen sales ($/bbl)	$ 24.51	$ —	$ 13.88	$ —
Royalties ($/bbl)	(0.28)	—	(0.13)	—
Operating expenses - non-energy ($/bbl)	(28.63)	—	(26.15)	—
Operating expenses - energy ($/bbl)	(7.50)	—	(6.11)	—
Transportation and marketing ($/bbl)	(17.43)	—	(14.53)	—
THERMAL OIL OPERATING NETBACK[1] ($/bbl)	$ (29.33)	$ —	$ (33.03)	$ —

(1) Refer to "Advisories and Other Guidance" beginning on page 19 for additional information on Non-GAAP Financial Measures.

($ Thousands)	Three months ended June 30, 2016	2015	Six months ended June 30, 2016	2015
Blended bitumen sales	$ 19,500	$ —	$ 40,602	$ —
Cost of diluent	(9,545)	—	(25,901)	—
Total bitumen sales	9,955	—	14,701	—
Royalties	(114)	—	(139)	—
Operating expenses - non-energy	(11,630)	—	(27,694)	—
Operating expenses - energy	(3,048)	—	(6,468)	—
Transportation and marketing	(7,078)	—	(15,390)	—
THERMAL OIL OPERATING INCOME (LOSS)(1)	$ (11,915)	$ —	$ (34,990)	$ —

(1) Refer to "Advisories and Other Guidance" beginning on page 19 for additional information on Non-GAAP Financial Measures.

During the three months ended June 30, 2016, Athabasca averaged 5,358 bbl/d of bitumen production, a 24% decrease compared to 7,029 bbl/d during the first quarter of 2016. The decline in production was primarily due to a 19-day shutdown of Project 1 in May as a result of the regional Fort McMurray wildfires in the area and planned maintenance activities performed on the central processing facility in April.

On May 5, 2016, Athabasca shut-down Project 1 for 19 days due to the regional Fort McMurray wildfires. The decision to shut down the well sites and central processing facility was due to elevated safety risks from the fire's proximity to Project 1. Athabasca resumed operations at Project 1 near the end of May with production reaching pre-fire levels by mid-June. The fires caused no damage to the facility, field pipelines or well sites. Reservoir performance continues to align with subsurface modeling including the effects of the wildfire interruption. Athabasca exited the second quarter with monthly average June production of 7,831 bbl/d. The Company continues to ramp-up Project 1 and anticipates exiting the fourth quarter of 2016 with production nearing the facility namplate of 12,000 bbl/d.

The Thermal Oil Operating Netback for the three months ended June 30, 2016 was $(29.33)/bbl, a 17% improvement compared to $(35.34)/bbl/d during the first quarter of 2016. The improvement in the Thermal Oil Operating Netback was primarily due to higher underlying market commodity prices for bitumen during the second quarter of 2016, partially offset by lower production volumes. The Thermal Oil Operating Netback was also impacted by incremental site protection costs and facility restart expenditures as a result of the regional wildfires. Compared to the fourth quarter of 2015, the Thermal Oil Operating Netback during the three months ended June 30, 2016 improved by 39% primarily due to higher production volumes and improved market commodity prices for bitumen.

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 central processing facility to the Cheecham terminal and then to Edmonton. First sales from the dilbit pipeline were completed in January 2016.

During the six months ended June 30, 2016, no royalties were payable in respect of the Contingent Bitumen Royalty.

Segment Income (Loss)

The following table summarizes the Thermal Oil Segment income (loss) for the three and six months ended June 30, 2016 and 2015:

($ Thousands)	Three months ended June 30, 2016	2015	Six months ended June 30, 2016	2015
Thermal Oil Operating Income(1)	$ (11,915)	$ —	$ (34,990)	$ —
Depletion of oil and gas assets	(2,428)	—	(5,637)	—
Depreciation of infrastructure assets	(2,874)	—	(6,360)	—
Exploration expense	(76)	(236)	(221)	(469)
Gain on sale of assets	—	—	—	912
THERMAL OIL SEGMENT INCOME (LOSS)	$ (17,293)	$ (236)	$ (47,208)	$ 443

(1) Refer to "Advisories and Other Guidance" beginning on page 19 for additional information on Non-GAAP Financial Measures.

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 facility is 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")

($ Thousands)	Three months ended June 30, 2016	Three months ended June 30, 2015	Six months ended June 30, 2016	Six months ended June 30, 2015
Salaries and benefits	$ 4,912	$ 8,667	$ 10,403	$ 19,132
Office costs	1,274	3,089	3,461	7,070
Legal, accounting and consulting	1,141	1,009	2,099	2,245
Stakeholder relations	209	89	593	480
Capitalized staff and environment costs	(2,081)	(4,584)	(4,114)	(12,287)
TOTAL GENERAL AND ADMINISTRATIVE EXPENSES	$ 5,455	$ 8,270	$ 12,442	$ 16,640
Capitalization rate	28%	36%	25%	42%

During the three and six months ended June 30, 2016, salaries and benefits declined by $3.8 million and $8.7 million, respectively, compared to the same periods in the prior year. The declines were 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 periods in the prior year, office costs declined by $1.8 million and $3.6 million during the three and six months ended June 30, 2016, respectively, primarily due to office lease provisions on under-utilized space taken 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 half of 2016 as a result of ongoing cost saving initiatives and sub-lease recoveries.

Capitalized staff and environment costs decreased during the three and six months ended June 30, 2016 compared to the same periods 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 and second quarters of 2016. For the six months ended June 30, 2015, Athabasca incurred $17.0 million in restructuring and other charges consisting of 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

For the three and six months ended June 30, 2016, Athabasca incurred stock-based compensation expense of $3.1 million and $4.7 million, respectively, compared to $4.9 million and $5.9 million during the same periods in the prior year. Stock-based compensation expense decreased during both periods primarily due to lower fair values on new equity awards granted to employees and directors during 2015 and 2016, partially offset by lower capitalization rates from lower Thermal Oil and Light Oil capital activity in the first half of 2016.

Financing and Interest

($ Thousands)	Three months ended June 30, 2016	2015	Six months ended June 30, 2016	2015
Financing and interest expense on indebtedness	$ 16,917	$ 16,533	$ 35,101	$ 31,629
Accretion of provisions	1,901	1,580	3,861	3,418
Amortization of debt issuance costs	8,583	1,805	10,438	3,623
Capitalized financing and interest	—	(16,740)	—	(33,914)
TOTAL FINANCING AND INTEREST	$ 27,401	$ 3,178	$ 49,400	$ 4,756

During the three and six months ended June 30, 2016 and 2015, financing and interest expenses were primarily attributable to three debt instruments held by the Company. Interest expense and amortization of debt issuance costs were incurred on the Company's $550.0 million senior secured second lien notes (the "Notes") which were issued during the fourth quarter of 2012. The Notes bear interest at a rate of 7.5% per annum. The Company also incurred interest and amortization of debt issuance costs on the US$225.0 million Term Loan issued in the second quarter of 2014. The Term Loan bore interest at a rate of LIBOR plus 7.25%, subject to a 1% LIBOR floor. Athabasca also incurred standby fees and fees on issued letters of credit on its $125.0 million Credit Facility and its US $50.0 million delayed-draw Term Loan.

During the second quarter of 2016, Athabasca repaid the Term Loan and canceled its undrawn US$50.0 million delayed-draw Term Loan. The Company also amended its undrawn Credit Facility which included a reduction of the facility from $125.0 million to $44.5 million (undrawn). In conjunction with the Credit Facility amendment, all letters of credit issued and outstanding under the Credit Facility were transferred to the Company's new $110.0 million Letter of Credit Facility. As at June, 30, 2016, no letters of credit remain outstanding under the Credit Facility and $100.6 million were outstanding under the Letter of Credit facility.

During the three and six months ended June 30, 2016, Athabasca incurred higher financing and interest expense on indebtedness of $0.4 million and $3.5 million, respectively, compared to the same periods in the prior year. The increases were primarily due to an increase in letters of credit issued and outstanding compared to the same periods in the prior year and financing costs relating to the Company's 2016 debt restructuring activities. The increases in financing and interest costs were partially offset by lower interest expense as a result of the repayment of the Term Loan and the cancellation of the delayed-draw Facility during the second quarter of 2016.

During the three and six months ended June 30, 2016, amortization of debt issuance costs increased by $6.8 million compared to the same periods in the prior year, primarily due to the acceleration of debt issuance costs due to the Term Loan repayment and Credit Facility amendments completed during the second quarter of 2016.

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

($ Thousands)	Three months ended June 30, 2016	2015	Six months ended June 30, 2016	2015
Interest on cash, cash equivalents and short-term investments	$ 1,452	$ 2,058	$ 2,843	$ 4,014
Interest on promissory notes	592	1,235	1,182	3,291
Accretion of capital-carry receivable	1,612	—	1,612	—
Other	—	129	70	384
TOTAL INTEREST INCOME AND OTHER	$ 3,656	$ 3,422	$ 5,707	$ 7,689

During the three and six months ended June 30, 2016, interest income on cash, cash equivalents, short-term investments and promissory notes decreased by $1.2 million and $3.3 million, respectively, compared to the same periods in the prior year. The decreases were primarily due to higher average balances of cash, cash equivalents, short-term investments and promissory notes during the first and second quarters of 2015. Athabasca also earned higher interest income in the prior year periods due to higher interest rates during the three and six months ended June 30, 2015.

During the three and six months ended June 30, 2016, Athabasca also recognized $1.6 million in non-cash interest income from the time value of money accretion on the Company's capital-carry receivable from the Murphy Transaction from the closing date of May 13, 2016 to June 30, 2016.

Foreign Exchange Gain (Loss), Net

($ Thousands)	Three months ended June 30, 2016	Three months ended June 30, 2015	Six months ended June 30, 2016	Six months ended June 30, 2015
Unrealized foreign exchange gain (loss)	$ —	$ 4,426	$ —	$ (19,246)
Realized foreign exchange gain	697	93	19,882	145
FOREIGN EXCHANGE GAIN (LOSS), NET	$ 697	$ 4,519	$ 19,882	$ (19,101)

Athabasca incurred foreign exchange gains and losses on the Company's US$225.0 million Term Loan, which was issued on May 7, 2014, and fully repaid on June 17, 2016.

During the three and six months ended June 30, 2016, Athabasca recognized a realized foreign exchange gain primarily due to a realized gain on the loan principal as the average value of the Canadian dollar increased relative to the US dollar by 7% from 1.38:1 to 1.29:1 from the beginning of the year until the date of the repayment of the Term Loan.

Athabasca recognized a net foreign exchange loss during the six months ended June 30, 2015 primarily due to an unrealized loss on the loan principal as the value of the Canadian dollar declined relative to the US dollar from 1.16:1 to 1.25:1. The net foreign exchange gain recognized in the second quarter of 2015 was a result of increases in the value of the Canadian dollar relative to the US dollar during the second quarter from 1.27 to 1.25.

Derivative Gain (Loss), Net

($ Thousands)	Three months ended June 30, 2016	Three months ended June 30, 2015	Six months ended June 30, 2016	Six months ended June 30, 2015
Unrealized derivative gain (loss)	$ —	$ (5,844)	$ —	$ 19,305
Realized derivative gain	(1,679)	659	(21,628)	1,421
DERIVATIVE GAIN (LOSS), NET	$ (1,679)	$ (5,185)	$ (21,628)	$ 20,726

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. In anticipation of its repayment of the Term Loan, on June 15, 2016, Athabasca unwound its foreign exchange par forward contract and received net cash proceeds of $41.0 million.

During the three and six months ended June 30, 2016, Athabasca recognized a realized derivative loss as the value of the Canadian dollar increased relative to the US dollar by 7% from 1.38:1 to 1.28:1 from the beginning of the year until the date that the foreign exchange par forward contract was settled.

Athabasca recognized a net unrealized derivative gain during the six months ended June 30, 2015 as the value of the Canadian dollar declined relative to the US dollar. The net derivative loss recognized in the second quarter of 2015 was a result of increases in the value of the Canadian relative to the US dollar during the second quarter of 2015.

CAPITAL EXPENDITURES

Light Oil Division

The following table summarizes the Light Oil capital expenditures for the three and six months ended June 30, 2016 and 2015:

($ Thousands)	Three months ended June 30, 2016	Three months ended June 30, 2015	Six months ended June 30, 2016	Six months ended June 30, 2015
Greater Placid area				
Drilling, completion and equipping	2,752	191	22,974	14,410
Land acquisitions	335	—	710	—
Operations and other	2,082	32	5,747	—
	5,169	223	29,431	14,410
Greater Kaybob area				
Drilling, completion and equipping	193	7,215	6,054	63,866
Land acquisitions	—	6,190	—	9,992
Operations and other	156	1,331	691	5,932
	$ 349	$ 14,736	$ 6,745	$ 79,790
TOTAL LIGHT OIL CAPITAL EXPENDITURES(1)(2)	$ 5,518	$ 14,959	$ 36,176	$ 94,200
Less: Greater Kaybob capital carry	$ (1,474)	—	$ (1,474)	—
Net cash outflow from Light Oil capital expenditures	$ 4,044	$ 14,959	$ 34,702	$ 94,200

(1) For the three and six months ended June 30, 2016, capital expenditures include $1.7 million and $3.4 million in capitalized staff costs, respectively (June 30, 2015 - $1.6 million and $4.0 million, respectively).

(2) During the six months ended June 30, 2016, $10.2 million of Light Oil PP&E expenditures related to assets sold as part of the Murphy Transaction

During the six months ended June 30, 2016, Athabasca spent $36.2 million in the Light Oil Division. The Company spent $29.4 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 network that connects the Company's Montney wells in the Greater Placid area to its regional infrastructure at Saxon. The pipeline system was operational in the first quarter of 2016.

Athabasca spent $6.7 million 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.

Thermal Oil Division

The following table summarizes the Thermal Oil capital expenditures for the three and six months ended June 30, 2016 and 2015:

($ Thousands)	Three months ended June 30, 2016	Three months ended June 30, 2015	Six months ended June 30, 2016	Six months ended June 30, 2015
Hangingstone Project 1	$ 1,533	$ 30,953	$ 1,731	$ 93,628
Hangingstone Expansion	285	768	747	2,591
Other Thermal Oil exploration	369	1,397	616	5,466
TOTAL THERMAL OIL CAPITAL EXPENDITURES(1)	$ 2,187	$ 33,118	$ 3,094	$ 101,685

(1) For the three and six months ended June 30, 2016, Thermal Oil capital expenditures include $0.4 million and $0.7 million, respectively, in capitalized staff costs (June 30, 2015 - $3.0 million and $8.3 million, respectively).

There were minimal capital expenditures in the Thermal Oil Division during the first and second quarters of 2016. During the three and six months ended June 30, 2015, Athabasca spent $31.7 million and $96.2 million on Project 1, respectively, 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 and suitable project funding.

OUTLOOK

In July 2016, Athabasca updated its capital budget and corporate production guidance in order to reflect the closing of the Murphy Transaction, the sale of the Contingent Bitumen Royalty, the impact of 2016 operations and a planned expansion to the Light Oil Montney program in the Greater Placid area.

The following tables reflect Athabasca's 2016 updated capital budget and corporate production guidance as at June 30, 2016:

2016 Capital Budget[1] ($ millions)	Full year
Light Oil Division	
Greater Kaybob area (Duvernay)[2]	$ 8
Greater Placid area (Placid)[3]	94
	102
Thermal Oil Division	
Hangingstone maintenance	7
Other thermal	4
	11
Capitalized general and administrative	8
Total capital expenditures	$ 121

(1) Figures may not add due to rounding.
(2) The Greater Kaybob area capital expenditures reflects Athabasca's 30% working interest, net of anticipated proceeds from the capital-carry receivable.
(3) The Greater Placid area capital expenditures reflects Athabasca's 70% working interest.

2016 Operational & Financial Guidance ($ millions, unless otherwise noted)	Full year
Light Oil (net)	
Production (boe/d)	4,500 - 5,000
Liquids weighting (%)	50%
Light Oil Operating Income[1]	$ 25
Light Oil Operating Netback ($/boe)	$ 14
Thermal Oil	
Bitumen production (bbl/d)	7,500 - 8,500
Thermal Oil Operating Income[1]	$ (50)
Corporate	
Production (boe/d)	12,000 - 13,500
Liquids weighting (%)	82%
Funds Flow from Operations[1]	$ (99)
Net Debt	$ 35
Cash and cash equivalents	$ 510
Commodity assumptions[2]	
WTI (US$/bbl)	$ 42.61
Edmonton Par (C$/bbl)	$ 51.14
Western Canadian Select (C$/bbl)	$ 36.96
AECO Gas (C$/mcf)	$ 1.97
FX (US$/C$)	0.76

(1) The Light Oil Operating Income, Thermal Oil Operating Income and Funds Flow from Operations estimates reflect the mid-point of the production guidance. Refer to "Advisories and Other Guidance" beginning on page 19 for additional information on Non-GAAP Financial Measures.
(2) Commodity assumptions reflects strip pricing as at July 5, 2016.

In December 2015, Athabasca released its initial 2016 Light Oil capital budget of $71 million with average production guidance of 7,000 - 8,000 boe/d. Following closing of the Murphy Transaction in the second quarter of 2016, Athabasca updated its 2016 Light Oil capital expenditures budget to $42 million (net) and updated the Company's anticipated average Light Oil production guidance to 4,500 - 5,000 boe/d (net) to reflect the Company's net 70% operated working interest in the Greater Placid Area and net 30% non-operated working interest in the Greater Kaybob Area.

In July 2016, Athabasca increased its Light Oil capital budget to $102 million (net) primarily to include an accelerated Montney development program in the Greater Placid area during the second half of 2016. Annual Light Oil production guidance remains unchanged between 4,500 - 5,000 boe/d (net). The Greater Placid area second half development program will now include the drilling of 12 development wells, the completion and tie-in of the 7-30 four well pad and long-lead commitments on an oil battery to accommodate mid-term growth plans. This increased activity will drive the Company's Light Oil production growth in early 2017.

In the Thermal Oil Division, the Fort McMurray wildfire and other unplanned maintenance downtime that occurred during the first half of 2016 impacted Athabasca's anticipated annual average production volumes. Revised 2016 production guidance is anticipated to be 7,500 - 8,500 bbl/d. There were no changes to the 2016 capital budget in the Thermal Oil Division.

The Company's consolidated 2016 capital budget now stands at $121 million, with consolidated 2016 production guidance of 12,000 boe/d to 13,500 boe/d per day.

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, cash equivalent and short-term investment accounts. Until required, excess cash will be invested in short-term deposits and investments.

Funding

Including cash proceeds from the Murphy Transaction and the Contingent Bitumen Royalty, and the Company's recently completed debt and credit facility refinancing activities, as at June 30, 2016, Athabasca had Liquidity[(1)] of $606.7 million including cash and cash equivalents of $447.3 million, short term investments of $25.5 million and a promissory note of $133.9 million receivable in the third quarter of 2016. The Company also has an additional $217.6 million (undiscounted as at June 30, 2016) of funding available through the capital-carry receivable from Murphy that will be used to fund the development of the Greater Kaybob area in the Light Oil Division over the next five years. Balance sheet strength and flexibility will continue to remain a key priority for Athabasca going forward.

It is anticipated that Athabasca's 2016 and 2017 capital and operating budgets, including continued development activities in the Light Oil segment, the ramp-up of Project 1 and any additional debt repayments will be funded with existing cash and cash equivalents, short-term investments, the remaining Promissory Note, operating income from the Light Oil and Thermal Oil segments, the capital-carry, issuance of additional debt or equity and available credit. Beyond 2017, 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, short-term investments, the capital-carry receivable, a reasonable level of debt, equity or 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 segment and at Project 1, 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 June 30, 2016 and December 31, 2015:

($ Thousands)	June 30, 2016	December 31 2015
Long-term debt	$ 544,042	$ 838,205
Less:		
Current assets	676,186	746,651
Current portion of derivative asset (included in current assets)	—	(5,382)
Accounts payable and accrued liabilities	(41,310)	(54,707)
Current portion of long-term debt	—	(3,068)
	634,876	683,494
NET DEBT[(1)]	$ (90,834)	$ 154,711

Senior Secured Second Lien Notes

On November 19, 2012, Athabasca issued Senior Secured Second Lien Notes (the "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.

(1) Refer to "Advisories and Other Guidance" beginning on page 19 for additional information on Non-GAAP Financial Measures.

Senior Secured Term Loans

On May 7, 2014, Athabasca entered into a US$225.0 million Term Loan which was fully drawn and a US$50 million committed delayed draw term loan which remained undrawn. The Term Loan amortized in equal quarterly installments in an aggregate annual amount equal to 1.00% of the original principal amount. Borrowings on drawn amounts under the Term Loan bore interest at a floating rate based on LIBOR plus 7.25%, subject to a LIBOR floor of 1.00%. On June 17, 2016, Athabasca repaid the principal outstanding on the Term Loan at par for $286.8 million (US$221.1 million). The undrawn delayed draw term loan was also canceled in the second quarter of 2016.

Revolving Senior Secured Credit Facility

On June 17, 2016, Athabasca amended its $125.0 million Credit Facility which included a reduction of the amount of available credit to $44.5 million. The Credit Facility is held with a syndicate of financial institutions and is available on a revolving basis until April 30, 2017. As at June 30, 2016, the Credit Facility was undrawn.

Amounts borrowed under the Credit Facility bear interest at a floating rate based on the applicable Canadian prime rate, US base rate, LIBOR or bankers' acceptance rate, plus a margin of between 2.50% and 5.00% depending on the type of borrowing and the Company's indebtedness to consolidated cash flow ratio. The Company incurs a standby fee on the undrawn portion of the Credit Facility of between 0.875% and 1.25% based on the Company's indebtedness to consolidated cash flow ratio. As part of the Credit Facility restructuring, all letters of credit issued and outstanding under the Credit Facility were transferred to a new Letter of Credit Facility (discussed below) and no letters of credit remain outstanding under the Credit Facility.

Bilateral Cash-Collateralized Letter of Credit Facility

Concurrent with the amendments to the Credit Facility, on June 17, 2016, Athabasca entered into a $110.0 million 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 used to satisfy certain 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 restricted cash-collateral account equivalent to 101% of the value of any and all letters of credit issued under the facility. As at June 30, 2016, Athabasca had $100.6 million in letters of credit issued and outstanding under the Letter of Credit Facility.

Commitments and Contingencies

The following table summarizes Athabasca's estimated future minimum commitments as at June 30, 2016 for the following five years and thereafter:

($ Thousands)	2016	2017	2018	2019	2020	Thereafter	Total
Transportation	$ 26,675	$ 53,922	$ 49,015	$ 51,749	$ 51,463	$ 856,200	$ 1,089,024
Repayment of long-term debt(1)	—	550,000	—	—	—	—	550,000
Interest expense on long-term debt	20,625	36,094	—	—	—	—	56,719
Office leases	1,226	2,452	2,452	2,452	2,452	11,808	22,842
Purchase commitments and other	7,263	—	—	—	—	—	7,263
Drilling rigs	1,401	2,915	—	—	—	—	4,316
TOTAL COMMITMENTS	$ 57,190	$ 645,383	$ 51,467	$ 54,201	$ 53,915	$ 868,008	$ 1,730,164

(1) The Term Loan was repaid on June 17, 2016.

Excluded from the table above is a commitment for $125.5 million of office leases which were assigned to a third party in December 2013.

Athabasca anticipates that a portion of its transportation commitments in the Light Oil Division will be reassigned to Murphy during the third quarter of 2016.

Athabasca is responsible for the retirement of its resource assets at the end of their useful lives. The total future costs to reclaim the Company's oil and gas assets are estimated by management and recognized as a provision in the consolidated financial statements.

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 is, from time to time, 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 currently represented by the carrying amounts of cash, short-term investments, accounts receivable, income tax receivable, the promissory note, restricted cash and long-term receivables and other on the consolidated balance sheets. Cash and short-term investments 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 June 30, 2016 and December 31, 2015 Athabasca's cash, cash equivalents, short-term investments and restricted cash were held with five counterparties and four counterparties, respectively. 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 June 30, 2016, the largest institution held 33% of the balances (December 31, 2015 - 32%).

The follow table summarizes the concentration of accounts receivables held by Athabasca as at June 30, 2016 and December 31, 2015:

Concentration of receivables (as at)	June 30, 2016	December 31, 2015
Current portion of capital-carry receivable	31%	—%
Petroleum and natural gas sales receivables (collected within 30 days)	26%	40%
Joint interest billings and equipment disposals	21%	18%
Accrued interest on the promissory notes	13%	12%
GST receivables and other	9%	30%

Management believes collection risk on the outstanding accounts receivables as at June 30, 2016 is low given the high credit quality of the Company's material counterparties. No material amounts were past due at June 30, 2016.

As at June 30, 2016, Athabasca holds the 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., is a wholly owned subsidiary of PetroChina International Investment Company Limited, 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.

Long-term receivables and other of $181.4 million primarily consists of the capital-carry receivable recognized in respect of the Murphy Transaction. Management believes that credit risk associated with the capital-carry receivable is low given the high credit quality of the Murphy subsidiary that has guaranteed the obligation. Timing of the recovery of the capital-carry is dependent on the amount and timing of capital expenditures in the Greater Kaybob area, subject to a minimum annual recovery to be realized by Athabasca from Murphy, as set out in Greater Kaybob Joint Development Agreement.

Foreign exchange risk

Athabasca was previously 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 was accounted for as a derivative instrument and changes in the valuation were recognized in net income (loss) and the associated liability or asset was recognized on the balance sheet. During the second quarter of 2016, concurrent with the repayment of the Term Loan, Athabasca unwound its derivative contract and received net cash proceeds of $41.0 million.

The following tables summarizes the change in the derivative asset during the six months ended June 30, 2016 and the year ended December 31, 2015:

As at		June 30, 2016		December 31, 2015
OPENING DERIVATIVE ASSET	$	62,584	$	12,638
Unrealized derivative gain		—		49,946
Realized derivative loss		(21,628)		—
Receipt of proceeds from derivative unwind		(40,956)		—
CLOSING DERIVATIVE ASSET	$	—	$	62,584
Presented as:				
Current portion of derivative asset	$	—	$	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 $548.9 million (December 31, 2015 - $480.6 million), from a 1.00% change in interest rates, would be approximately $5.5 million for a 12 month period (year ended December 31, 2015 - $4.8 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 six months ended June 30, 2016, Athabasca issued 1.6 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 July 20, 2016	
Common shares issued and outstanding	406,079,750
Convertible securities:	
Stock options	9,680,215
Restricted share units (2010 RSU Plan)	4,784,550
Restricted share units (2015 RSU Plan)	5,175,834
Performance share units	2,673,700
Deferred share units	1,098,234

For additional information regarding these compensation plans, refer to the 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)	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	45.59	33.45	42.18	46.43	57.94	48.63	93.00	97.19
WTI (C$/bbl)	58.81	45.83	56.52	60.82	71.27	60.30	107.88	108.85
Western Canadian Select (C$/bbl)	41.62	26.30	36.86	43.29	71.24	60.35	83.03	105.84
Edmonton Par (C$/bbl)	54.78	40.67	52.85	56.17	67.63	51.79	94.49	97.03
Edmonton Condensate (C5+) (C$/bbl)	56.80	46.32	54.52	56.94	69.81	55.42	100.42	99.87
NYMEX Henry Hub (US$/MMBtu)	1.95	2.09	2.27	2.80	2.64	2.98	4.39	4.07
AECO (C$/GJ)	1.32	1.74	2.33	2.75	2.53	2.61	4.25	3.82
Foreign exchange (CAD : USD)	1.29	1.37	1.34	1.31	1.23	1.24	1.16	1.12
LIGHT OIL DIVISION								
Sales volumes (boe/d)	5,743	6,319	5,873	5,145	5,459	5,877	6,035	6,381
Realized price ($/boe)	26.93	21.73	27.39	31.34	34.43	29.35	44.66	56.90
Revenues[(2)] ($)	13,936	12,440	17,624	14,043	17,666	13,981	21,757	29,892
Light Oil Operating Income[(1)] ($)	7,215	4,908	10,551	6,096	10,689	6,578	12,431	21,154
Light Oil Operating Netback[(1)] ($/boe)	13.80	8.53	19.50	12.88	21.51	12.46	22.38	36.03
Capital expenditures ($)	5,518	30,658	50,921	31,465	14,959	79,241	87,870	19,772
THERMAL OIL DIVISION								
Bitumen production (bbl/d)[(3)(4)]	5,358	7,029	5,708	2,105	—	—	—	—
Sales volumes (bbl/d)[(3)(4)]	4,463	7,176	4,096	1,792	—	—	—	—
Realized bitumen price ($/bbl)	24.51	7.27	21.23	17.54	—	—	—	—
Revenues[(2)] ($)	19,386	21,076	15,033	6,145	—	—	—	—
Thermal Oil Operating Loss[(1)(4)] ($)	(11,915)	(23,074)	(18,166)	(12,146)	—	—	—	—
Thermal Oil Operating Netback[(1)(4)] ($/bbl)	(29.33)	(35.34)	(48.22)	(73.67)	—	—	—	—
Capital expenditures	2,187	916	2,257	9,366	33,118	68,504	78,876	89,455
OPERATING RESULTS								
Cash Flow from Operations ($)	5,759	(38,017)	(54,496)	(17,933)	8,576	(2,610)	(8,883)	30,371
Funds Flow from Operations[(1)] ($)	(27,304)	(39,982)	(30,141)	(24,223)	5,085	3,162	(2,520)	7,203
Net income (loss) ($)	(59,169)	(65,129)	(604,375)	(38,241)	(29,044)	(25,112)	(129,507)	(19,939)
Net income (loss) per share - basic ($)	(0.15)	(0.16)	(1.50)	(0.09)	(0.07)	(0.06)	(0.32)	(0.05)
BALANCE SHEET ITEMS								
Cash and cash equivalents ($)	447,282	493,510	559,487	671,447	582,396	570,290	531,475	722,747
Short-term investments ($)	25,533	—	—	—	—	92,873	47,618	—
Promissory notes - short-term ($)	133,892	133,892	133,892	133,892	150,000	150,000	450,000	450,000
Promissory notes - long-term ($)	—	—	—	—	133,892	133,892	133,892	133,892
Assets held for sale ($)	—	466,159	—	—	—	—	—	—
Total assets ($)	3,028,938	3,394,367	3,462,442	4,160,344	4,173,704	4,244,486	4,297,803	4,413,935
Long-term debt ($)	544,042	820,478	838,205	827,773	807,167	810,758	786,649	777,528
Net Debt[(1)] ($)	(90,834)	209,809	154,711	55,433	109,713	68,005	(123,625)	(305,161)
Shareholders' equity ($)	2,363,396	2,419,651	2,482,140	3,085,499	3,119,224	3,141,453	3,164,186	3,289,083

(1) Refer to "Advisories and Other Guidance" beginning on page 19 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.

ACCOUNTING POLICIES AND ESTIMATES

During the six months ended June 30, 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 “Net Debt”, “Funds Flow from Operations”, "Light Oil Operating Income", “Light Oil Operating Netback”, "Thermal Oil Operating Income", "Thermal Oil Operating Netback" and "Liquidity" 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 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 14 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 and six months ended June 30, 2016 and 2015 to Funds Flow from Operations:

($ Thousands)	Three months ended June 30, 2016	Three months ended June 30, 2015	Six months ended June 30, 2016	Six months ended June 30, 2015
Cash flow from operating activities	$ 5,759	$ 8,576	$ (32,268)	$ 5,922
Receipt of proceeds from derivative unwind	(40,956)	—	(40,956)	—
Restructuring and other charges, excluding change in long-term portion of office lease provision	—	(180)	—	13,340
Changes in non-cash working capital	5,071	(3,532)	1,299	(13,389)
Settlement of provisions	1,774	221	3,222	2,328
Other items	1,048	—	1,283	—
FUNDS FLOW FROM OPERATIONS	$ (27,304)	$ 5,085	$ (67,420)	$ 8,201

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 ongoing 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 7 reconciles Light Oil Operating Income to *Note 11 - Segmented Information* in the unaudited condensed interim consolidated financial statements for the three and six months ended June 30, 2016.

The Thermal Oil Operating Income and Thermal Oil Operating Netback measures in this MD&A (including the comparatives thereto) are calculated by subtracting the 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 8 reconciles Thermal Oil Operating Income to *Note 11 - Segmented Information* in the unaudited condensed interim consolidated financial statements for the three and six months ended June 30, 2016.

The Liquidity measure in this MD&A is calculated by adding cash and cash equivalents, short-term investments and the promissory note on the Company's consolidated balance sheet. The Liquidity measure allows management and others to evaluate the Company's ability to finance its capital and operating activities in the short-term.

Risk Factors

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

- weakness in the oil and gas industry;
- fluctuations in market prices for crude oil, natural gas, condensate 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 the related financing;
- 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;
- dependence upon Murphy as a working interest participant in its Light Oil assets and as operator of the Greater Kaybob assets;
- risks related to the Credit Facility, the Letter of Credit Facility 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;
- risks associated with events of force majeure;
- 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;
- 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 Thermal Oil Operating Netbacks will improve as production increases; the expectation that the Contingent Bitumen Royalty will not materially impact the economics of future Hangingstone Expansion phases or other future Thermal Oil exploration projects; the timing of receipt of regulatory approval in 2016 for the Hangingstone Expansion; the timing of drilling, completion and tie-in operations in the Company's Light Oil division; 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 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; the Company's plans for, and results of, exploration and development activities; 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; Athabasca's continued balance-sheet strength; reassigning a portion of the Company's transportation agreements in the Light Oil Division to Murphy; the Company's business and financing plans and strategies; expectations regarding the 2016 capital budget; the Company's anticipated sources of funding for 2016 and beyond; the Company's estimate future minimum capital commitments; 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; 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 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 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, GHG 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, reassigning a portion of the Company's transportation commitments in the Light Oil Division to Murphy; risks associated with events of force majeure; risks related to the Credit Facility, the Letter of Credit Facility 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; 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 include: 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 include: 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, 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
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
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.