Management's Discussion and Analysis

Q1 2017

ATHABASCA OIL CORPORATION

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Management's Discussion and Analysis

This Management's Discussion and Analysis of the financial condition and results of operations ("MD&A") of Athabasca Oil Corporation ("Athabasca" or the "Company") is dated May 3, 2017 and should be read in conjunction with the audited consolidated financial statements of the Company for the years ended December 31, 2016 and 2015. 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 21 for important information regarding the Company's reserves and resource information included in this MD&A. For a listing of abbreviations, refer to "Abbreviations" on page 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 9, 2017 ("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 Division

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 ("Greater Placid area") and Kaybob ("Greater Kaybob area") near the town of Fox Creek, Alberta.

Athabasca has a 70% operated working interest in over 65,000 gross acres of Montney lands within the Greater Placid area, of which greater than 30,000 acres are considered commercially prospective, with a potential inventory estimated between 150 - 200(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 with exposure to both liquids-rich gas and volatile oil opportunities and an inventory of approximately 1,500(1) gross drilling locations. As at December 31, 2016, the Light Oil Division had approximately 42 MMboe of Proved plus Probable Reserves (net)(2). During the three months ended March 31, 2017, the Light Oil Division produced 3,421 boe/d (net).

Thermal Oil Division

Athabasca's Thermal Oil Division consists of two operating oil sands projects and a large resource base of exploration areas in the Athabasca region of northeastern Alberta.

On January 31, 2017, Athabasca completed an acquisition of Canadian oil sands assets from Statoil Canada Ltd. and its wholly-owned affiliate KKD Oil Sands Partnership, both subsidiaries of Statoil ASA (collectively "Statoil"). The acquired assets include the operating Leismer Thermal Oil Project (the "Leismer Project"), the delineated Corner exploration area and related strategic infrastructure (the "Leismer Corner Acquisition"). From the date of acquisition to the end of the first quarter of 2017, the Leismer Project produced 22,521 bbl/d. Athabasca is also currently ramping up its Hangingstone Thermal Oil Project (the "Hangingstone Project) towards design capacity of 12,000 bbl/d. During the three months ended March 31, 2017, the Hangingstone Project produced 8,552 bbl/d.

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

As at December 31, 2016, after giving effect to the Leismer Corner Acquisition as if it had been completed on December 31, 2016, the Thermal Oil Division had pro forma Proved plus Probable Reserves of approximately 1.1 billion barrels(2), and approximately 4.0 billion barrels (risked)(2) (6.5 billion barrels unrisked)(2) of Best Estimate Contingent Resources.

(1) Refer to "Advisories and Other Guidance" beginning on page 18 for additional information regarding the Company's drilling locations.
(2) Based on the reports of Athabasca's independent reserve evaluators effective December 31, 2016. Refer to page 21 and the AIF for additional important information about the Company's Reserves and Contingent Resources and Reserves and Contingent Resources acquired as part of the Leismer Corner Acquisition.

FINANCIAL & OPERATIONAL HIGHLIGHTS

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

($ Thousands, except volume, boe and share amounts)[1]		March 31, 2017		March 31, 2016
CONSOLIDATED PRODUCTION				
Petroleum and natural gas volumes (boe/d)		26,737		13,348
LIGHT OIL DIVISION				
Petroleum and natural gas volumes (boe/d)		3,421		6,319
Light Oil Operating Income[1]	$	6,863	$	4,908
Light Oil Operating Netback[1] ($/boe)	$	22.28	$	8.53
Capital expenditures	$	77,646	$	30,658
Recovery of capital-carry through capital expenditures	$	(10,680)	$	—
THERMAL OIL DIVISION				
Bitumen production (bbl/d)		23,316		7,029
Thermal Oil Operating Income (loss)[1]	$	12,341	$	(23,074)
Thermal Oil Operating Netback[1] ($/bbl)	$	5.89	$	(35.34)
Capital expenditures[2]	$	10,868	$	916
CASH FLOW AND FUNDS FLOW				
Cash flow from operating activities	$	(52,896)	$	(38,017)
Cash flow from operating activities per share (basic and diluted)	$	(0.11)	$	(0.09)
Funds Flow from Operations	$	(1,649)	$	(39,982)
Funds Flow from Operations per share (basic and diluted)	$	—	$	(0.10)
NET LOSS AND COMPREHENSIVE LOSS				
Net loss and comprehensive loss	$	(29,162)	$	(65,129)
Net loss and comprehensive loss per share (basic and diluted)	$	(0.06)	$	(0.16)
SHARES OUTSTANDING				
Weighted average shares outstanding (basic and diluted)		472,157,006		404,511,104
ACQUISITIONS AND FINANCINGS				
Leismer Corner Acquisition[3]	$	(622,076)	$	—
Net proceeds from sale of assets	$	90,170	$	163
Net proceeds from issuance of 2022 Notes	$	542,554	$	—
Repayment of 2017 Notes	$	(550,000)	$	—

(1) Refer to "Advisories and Other Guidance" beginning on page 18 for additional information on Non-GAAP Financial Measures.
(2) Thermal Oil capital expenditures excludes the cost of the Leismer Corner Acquisition.
(3) Consists of cash of $431.3 million, common shares of $166.0 million and contingent payment obligations of $24.7 million.

As at ($ Thousands)		March 31, 2017		December 31, 2016
LIQUIDITY AND INDEBTEDNESS				
Cash and cash equivalents	$	212,999	$	650,301
Restricted cash	$	113,823	$	107,012
Capital-carry receivable (current and long-term portion - undiscounted)	$	202,789	$	213,469
Face value of long-term debt (current and long-term portion)	$	599,490	$	550,000

HIGHLIGHTS FOR THE THREE MONTHS ENDED MARCH 31, 2017

- **Consolidated Production** - During the three months ended March 31, 2017, the Company's corporate production increased by 100% to 26,737 boe/d, compared to 13,348 boe/d during the same period in the prior year. The increase was primarily due to the acquisition of the Leismer Project during the first quarter of 2017.

- **Greater Placid Development** - During the first quarter of 2017, Athabasca advanced its 20-well winter drilling program with all 20 wells rig-released ahead of spring break-up. During the first quarter, Athabasca also completed the construction of a battery at Placid to accommodate future production growth in the area. The battery was operational in early April and three of the multi-well pads were placed on production.

- **Greater Kaybob Development** - During the first quarter of 2017, Athabasca completed and brought on stream a two-well Duvernay pad in the Greater Kaybob area. Drilling commenced on an additional six horizontal Duvernay wells in the first quarter with all wells rig-released before spring break-up.

- **Leismer Corner Acquisition** - On January 31, 2017, Athabasca completed the acquisition of Statoil's Canadian oil sands assets including the operating Leismer Project, the delineated Corner exploration area and related strategic infrastructure. Consideration included $431.3 million cash (after purchase price adjustments) and 100 million Athabasca common shares. Athabasca also agreed to a series of annual contingent payments triggered at oil prices above US$65/bbl WTI for a four year term ending in 2020. The payments are capped at $75 million annually and $250 million over the term. The Leismer Corner Acquisition immediately drives a larger cash flow base and accelerates the Company's transition to sustainable free cash flow generation.

- **Leismer Operating Results** - From the date of acquisition on January 31, 2017 to the end of the first quarter, the Leismer Project averaged 22,521 bbl/d of bitumen production. Leismer Operating Netbacks were $12.66/bbl in the first quarter of 2017 with a realized bitumen price of $29.83/bbl.

- **Hangingstone Operating Results** - The Hangingstone Project averaged 8,552 bbl/d of bitumen production during the first quarter of 2017 and averaged approximately 9,200 bbl/d in March. Athabasca continues to ramp-up the project toward its design capacity of 12,000 bbl/d which is anticipated in 2018.

- **Contingent Bitumen Royalty** - During the three months ended March 31, 2017, Athabasca granted a Contingent Bitumen Royalty (the "Royalty") on its newly acquired Leismer and Corner assets for cash proceeds of $90.0 million. The Royalty is based on a linear-scale of 0% - 12% determined relative to a WCS benchmark price. The trigger for payment of the Royalty is a price of US$60/bbl WCS (~$75.0/bbl WTI)(1). Including the Royalty granted on the Company's legacy Thermal Oil assets during 2016, Athabasca has now raised total gross proceeds of close to $400.0 million through this unique funding structure.

- **Balance Sheet Refinancing** - During the first quarter of 2017, Athabasca completed a balance sheet refinancing which provides multi-year funding certainty, a strong liquidity outlook, and will allow the Company to advance its strategic objectives and maintain business flexibility. The refinancing, which closed on February 24, 2017, included the issuance of US$450.0 million (C$589.0 million) of five-year Senior Secured Second Lien Notes (the "2022 Notes"), the proceeds of which were used to repay the Company's existing $550.0 million Senior Secured Second Lien Notes (the "2017 Notes"). The Company also established a new $120.0 million reserve-based Revolving Senior Secured Credit Facility (the "New Credit Facility") and has commenced a commodity risk management program with the intention of hedging a minimum of 20,000 bbl/d in 2017 to protect cash flow and support the Company's capital plans.

- **Trans Mountain Pipeline Expansion** - On March 6, 2017, Athabasca acquired firm service on the Trans Mountain Pipeline Expansion (the "TMX Pipeline") by entering into a long-term transportation service agreement with Trans Mountain Pipeline L.P. to deliver up to 20,000 bbl/d of the Company's blended bitumen from Edmonton, Alberta to Burnaby, B.C. The expansion project is federally approved and is expected to be in-service in late 2019. The Company believes securing firm take-away capacity to multiple end markets is essential to its long-term strategy. The TMX Pipeline will provide Athabasca exposure to global oil demand growth.

(1) Based on a WCS differential of US$15/bbl and a foreign exchange rate of 0.75 US$/C$.

ACQUISITION OF THERMAL OIL ASSETS

On December 14, 2016, Athabasca entered into agreements with Statoil to acquire its Canadian oil sands assets including the operating Leismer Project, the delineated Corner exploration area and related strategic infrastructure. The Leismer Corner Acquisition had an effective date of January 1, 2017 and was completed on January 31, 2017.

On closing, Athabasca paid Statoil $431.3 million in cash, consisting of the initial cash purchase price of $435.0 million, net of $3.7 million in purchase price adjustments, and issued 100 million Athabasca common shares which were valued at $166.0 million based on Athabasca's January 31, 2017 closing share price of $1.66/share. Athabasca also agreed to a series of annual contingent payments triggered at oil prices above US$65/bbl WTI for a four year term ending in 2020. Each annual payment is calculated on one-third of the Leismer Project bitumen production multiplied by an oil price factor (monthly average US$WTI/bbl less US$65/bbl, adjusted for inflation). The payments are capped at $75.0 million annually and $250.0 million over the term. Athabasca incurred $7.6 million in acquisition costs associated with the Leismer Corner Acquisition.

The Leismer Project was commissioned in 2010 and has Proved Reserves(2) in place to support a flat production profile for over 30 years and a Reserve Life Index of approximately 70 years (utilizing Proved plus Probable Reserves). The Leismer Project and Corner assets have received regulatory approval for future development phases of up to a combined 80,000 bbl/d.

The acquired assets are high quality and resilient to lower commodity prices. The Leismer Project's steam oil ratio ("SOR") of less than 3.0x ranks it as one of the lowest among operating projects in the basin and operating income break-even is estimated at approximately US$44/bbl WTI(3).

Strategic infrastructure acquired as part of the acquisition includes ownership of dilbit and diluent pipelines from Leismer to the Cheecham Terminal, 300,000 barrels of storage capacity at the Cheecham Terminal and access to multiple sales points with marketing agreements on the Enbridge Waupisoo transportation pipeline.

SALE OF ASSETS

Sale of Contingent Bitumen Royalty to Burgess

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

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

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

The following table summarizes the Royalty rates applicable at different WCS benchmark prices:

Hangingstone, Leismer and Corner WCS benchmark price (US$/bbl)	Royalty rate
Below $60/bbl	--
$60/bbl to $139.99/bbl(1)	2% - 12%
$140/bbl and above	12%

Dover West, Birch and Grosmont WCS benchmark price (US$/bbl)	Royalty rate
Below $70/bbl	--
$70/bbl to $149.99/bbl(1)	2% - 12%
$150/bbl and above	12%

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

During the three months ended March 31, 2017, no amounts were payable in respect of the Royalty to Burgess.

(2) Refer to "Advisories and Other Guidance" beginning on page 18 for additional information on the Company's Reserves and Resources.
(3) Based on a WCS differential of US$15/bbl and a foreign exchange rate of 0.75 US$/C$.

Sale of Light Oil assets to Murphy

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 (the "Murphy Transaction"). 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. Athabasca received $267.5 million in cash, including purchase price adjustments from the January 1, 2016 effective date, and also recognized additional consideration of $219.0 million (undiscounted) in the form of a capital-carry in the Greater Kaybob area, whereby Murphy will fund 75% of Athabasca's share of development capital up to a maximum five year period. The carry supports approximately $1 billion of Duvernay investment over the next four years of which Athabasca's financial exposure is limited to $75 million to retain its 30% working interest.

BUSINESS ENVIRONMENT

Benchmark prices

Three months ended (monthly average)		March 31, 2017		March 31, 2016	Change
Crude oil:					
West Texas Intermediate (WTI) (US$/bbl)	$	51.91	$	33.45	55 %
West Texas Intermediate (WTI) (C$/bbl)	$	68.52	$	45.83	50 %
Western Canadian Select (WCS) (C$/bbl)	$	49.34	$	26.30	88 %
Edmonton Par (C$/bbl)	$	63.87	$	40.67	57 %
Edmonton Condensate (C5+) (C$/bbl)	$	68.73	$	46.32	48 %
Differential:					
WTI vs. WCS (US$/bbl)	$	(14.53)	$	(14.25)	(2)%
WTI vs. WCS (C$/bbl)	$	(19.18)	$	(19.53)	2 %
Differential as a % of WTI		(28)%		(43)%	35 %
Natural gas:					
NYMEX Henry Hub (US$/MMBtu)	$	3.32	$	2.09	59 %
AECO (C$/GJ)	$	2.55	$	1.74	47 %
Foreign exchange:					
USD : CAD		1.32		1.37	(4)%

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. For the three months ended March 31, 2017, the WTI price increased by 55%, compared to the same period in the prior year, primarily due to a lower global supply of crude oil following the curtailment of petroleum production by OPEC during the first quarter of 2017, as well as declining crude oil inventories outside of North America.

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 quarter in the prior year, the Canadian dollar WCS price increased by 88% during the three months ended March 31, 2017. The WCS differential remained consistent quarter over quarter as limited North American pipeline capacity continued to impact Athabasca's realized price for its blended bitumen sales.

The Edmonton Par price is the primary benchmark for crude oil sales in the Company's Light Oil Division. Consistent with the change in the WTI price, during the three months ended March 31, 2017, the average Edmonton Par price increased by 57% 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 its Leismer and Hangingstone Projects in order to deliver produced bitumen to the market. For the three months ended March 31, 2017, the average Edmonton Condensate (C5+) price increased by 48% compared to the same period in 2016.

In the Thermal Oil Division, the AECO price is the primary benchmark for natural gas purchases consumed by Athabasca in order to generate steam in the SAGD recovery process. For the three months ended March 31, 2017, the AECO price increased by 47% compared to the three months ended March 31, 2016. In the Light Oil Division, the NYMEX gas price is the primary benchmark for natural gas sales as Athabasca primarily delivers its sales product on the Fort Chicago pipeline. For the three months ended March 31, 2017, the average NYMEX price improved by 59% compared to the same period in the prior year.

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

Light Oil Operating Results

Three months ended	March 31, 2017	March 31, 2016
SALES VOLUMES		
Oil (bbl/d)	1,763	2,530
Natural gas (Mcf/d)	8,760	18,993
Natural gas liquids (bbl/d)	198	623
Total (boe/d)	3,421	6,319
Consisting of:		
Greater Placid area (boe/d)	2,016	694
% liquids	62%	52%
Greater Kaybob area (boe/d)	1,405	5,625
% liquids	51%	50%

Three months ended ($ Thousands, except volume and boe amounts)	March 31, 2017	March 31, 2016
Petroleum and natural gas sales	$ 11,999	$ 12,492
Midstream revenue	29	497
Royalties	(421)	(549)
Operating and transportation expenses	4,744	7,532
Light Oil Operating Income[(1)]	$ 6,863	$ 4,908
REALIZED PRICES		
Oil ($/bbl)	$ 60.08	$ 36.85
Natural gas ($/Mcf)	2.66	1.65
Natural gas liquids ($/bbl)	20.59	20.41
Realized price ($/boe)	38.97	21.73
Royalties ($/boe)	(1.37)	(0.96)
Operating and transportation expenses[(1)] ($/boe)	(15.32)	(12.24)
LIGHT OIL OPERATING NETBACK[(2)] ($/boe)	$ 22.28	$ 8.53

(1) Refer to “Advisories and Other Guidance” beginning on page 18 for additional information on Non-GAAP Financial Measures.
(2) For the three months ended March 31, 2017, operating and transportation expenses include midstream revenues of $0.09/boe (March 31, 2016 - $0.86).

During the three months ended March 31, 2017, Athabasca's Light Oil production averaged 3,421 boe/d, compared to 6,319 boe/d during the same quarter in the prior year. The lower production was primarily due to the sale of the Light Oil joint venture assets to Murphy on May 13, 2016, partially offset by production from 13 wells (seven Montney, six Duvernay) brought on stream during 2016. During the first quarter of 2017, Athabasca also tied-in a number of Montney and Duvernay wells late in the quarter.

Athabasca's Light Oil Operating Netback was $22.28/boe during the first quarter of 2017, compared to $8.53/boe during the first quarter of 2016, primarily due to higher realized prices for oil and gas. Athabasca's realized price increased by 79% to $38.97/boe primarily due to higher underlying benchmark prices for oil and natural gas and a higher liquids content in Athabasca's production.

Compared to the same period in the prior year, operating and transportation expenses per boe increased by 25% to $15.32/boe during the three months March 31, 2017. The increase was primarily due to higher clean oil trucking costs due to temporary capacity restrictions on the Pembina pipeline. Athabasca also completed an eight-day turnaround at its Saxon battery.

Light Oil Segment Income (Loss)

Three months ended ($ Thousands)	March 31, 2017	March 31, 2016
Light Oil Operating Income(1)	$ 6,863	$ 4,908
Depletion and depreciation	(4,610)	(10,829)
Exploration expense and other	(132)	18
LIGHT OIL SEGMENT INCOME (LOSS)	$ 2,121	$ (5,903)

(1) Refer to "Advisories and Other Guidance" beginning on page 18 for additional information on Non-GAAP Financial Measures.

Depletion of oil and gas assets declined by $6.2 million during the quarter ended March 31, 2017 compared to the same period in the prior year. The decline was primarily due to lower production as a result of the Murphy Transaction as well as lower depletion rates resulting from reserve additions from drilling activities in the second half of 2016.

Light Oil Capital Expenditures

Three months ended ($ Thousands)	March 31, 2017	March 31, 2016
Greater Placid area		
Drilling, completion and equipping	$ 46,430	$ 10,794
Facilities	18,131	9,431
Land acquisitions and other	79	4,043
	64,640	24,268
Greater Kaybob area		
Drilling, completion and equipping	12,385	2,072
Facilities	465	3,787
Land acquisitions and other	156	531
	$ 13,006	$ 6,390
TOTAL LIGHT OIL CAPITAL EXPENDITURES(1)(2)	77,646	30,658
Less: Greater Kaybob capital carry	(10,680)	—
Net cash outflow from Light Oil capital expenditures	$ 66,966	$ 30,658

(1) For the three months ended March 31, 2017, capital expenditures included $1.4 million in capitalized staff costs (March 31, 2016 - $1.6 million).
(2) During the three months ended March 31, 2016, $8.7 million of Light Oil PP&E expenditures related to assets sold as part of the Murphy Transaction.

Greater Placid area

Athabasca holds an operated 70% interest in the Greater Placid area primarily targeting the development of the Montney formation. Athabasca's Greater Placid assets are supported by jointly-owned regional infrastructure primarily consisting of the pipeline-connected Saxon battery and gas-processing facility.

During the first quarter of 2017, Athabasca advanced its 20-well winter drilling program in the Greater Placid area. All 20 wells were rig-released ahead of spring break-up, with three of the five multi-well pads on stream. Athabasca anticipates that the remaining pads will be brought on stream following spring break-up. Athabasca also completed construction of a battery in the Placid area to accommodate future production growth. The Placid battery has an initial design capacity of 10 Mbbl/d of hydrocarbon liquids and 36 mmcf/d of natural gas and will utilize a previously constructed pipeline network that connects the Company's Montney wells in the Greater Placid area to its regional infrastructure at Saxon. Oil and water production will be pumped to the existing Saxon battery for treating, water disposal and oil delivery into the Pembina pipeline system. The Placid battery commenced operations in early April.

Greater Kaybob area

Athabasca holds a non-operated 30% interest in the Greater Kaybob area primarily targeting the development of the Duvernay formation. Athabasca's Greater Kaybob assets are supported by jointly-owned regional infrastructure primarily consisting of the Kaybob East and Kaybob West batteries and a network of gas pipelines which connect the facilities to two regional third party gas processing plants.

Including the recovery of the capital-carry, Athabasca's net cash outflow from capital expenditures in the Greater Kaybob area was $2.3 million during the three months ended March 31, 2017. Athabasca completed and brought on stream a two-well Duvernay pad and commenced drilling of six horizontal Duvernay wells which were all rig-released before spring break-up. An additional 10 Duvernay wells are anticipated to be spudded throughout the remainder of 2017.

THERMAL OIL DIVISION

Leismer Operating Results

	Two months ended March 31, 2017	Three months ended March 31, 2017
VOLUMES		
Bitumen production (bbl/d)	22,521	14,764
Bitumen sales (bbl/d)	22,324	14,635
Blended bitumen sales (bbl/d)	32,666	21,414

Three months ended ($ Thousands, except volume and bbl amounts)		March 31, 2017
Blended bitumen sales	$	89,027
Cost of diluent		(49,733)
Total bitumen sales		39,294
Royalties		(949)
Operating expenses - non-energy		(13,234)
Operating expenses - energy		(4,877)
Transportation and marketing		(3,561)
Leismer Operating Income(1)(2)	$	16,673
REALIZED PRICE		
Blended bitumen sales ($/bbl)	$	46.19
Bitumen sales ($/bbl)	$	29.83
Royalties ($/bbl)		(0.72)
Operating expenses - non-energy ($/bbl)		(10.05)
Operating expenses - energy ($/bbl)		(3.70)
Transportation and marketing ($/bbl)		(2.70)
LEISMER OPERATING NETBACK(1)(2) ($/bbl)	$	12.66

(1) Refer to "Advisories and Other Guidance" beginning on page 18 for additional information on Non-GAAP Financial Measures.
(2) The Leismer Project was acquired on January 31, 2017. The table above reflects Leismer Operating Income from February and March of 2017.

Athabasca completed the Leismer Corner Acquisition and assumed operatorship of the Leismer Project on January 31, 2017. From the date of acquisition to the end of the first quarter of 2017, the Leismer Project averaged 22,521 bbl/d. Going forward, the Company intends to maintain a stable production base of 22,000 bbl/d to 24,000 bbl/d at Leismer with operations focused on production optimization and drilling of additional sustaining and infill wells.

During the quarter ended March 31, 2017, the Lesimer Operating Netback was $12.66/bbl with a realized bitumen price of $29.83/bbl.

Energy operating expenses were $3.70/bbl during the first quarter of 2017 and primarily consisted of electricity to power the facility and natural gas which is used to create steam for the SAGD recovery process. Non-Energy operating costs were $10.05/bbl and include all other operational expenditures relating to production.

During the three months ended March 31, 2017, transportation and marketing expenses were $2.70/bbl. Purchased diluent and blended bitumen delivered to and from the Leismer Project, respectively, are transported via wholly-owned pipeline infrastructure which is connected to the Cheecham Terminal. As part of the Leismer Corner Acquisition, Athabasca also acquired 300,000 barrels of storage capacity at the Cheecham Terminal and access to multiple sales points with marketing agreements on the Enbridge Waupisoo transportation pipeline.

Hangingstone Operating Results

Three months ended	March 31, 2017	March 31, 2016
VOLUMES		
Bitumen production (bbl/d)	8,552	7,029
Bitumen sales (bbl/d)	8,622	7,176
Blended bitumen sales (bbl/d)	12,266	10,175

Three months ended ($ Thousands, except volume and bbl amounts)	March 31, 2017	March 31, 2016
Blended bitumen sales	$ 50,476	$ 21,101
Cost of diluent	(28,216)	(16,356)
Total bitumen sales	22,260	4,745
Royalties	(456)	(25)
Operating expenses - non-energy	(13,703)	(16,063)
Operating expenses - energy	(5,579)	(3,420)
Transportation and marketing	(9,145)	(8,311)
Hangingstone Operating Loss(1)	$ (6,623)	$ (23,074)
REALIZED PRICE		
Blended bitumen sales ($/bbl)	$ 45.72	$ 22.79
Bitumen sales ($/bbl)	$ 28.69	$ 7.27
Royalties ($/bbl)	(0.59)	(0.04)
Operating expenses - non-energy ($/bbl)	(17.66)	(24.60)
Operating expenses - energy ($/bbl)	(7.19)	(5.24)
Transportation and marketing ($/bbl)	(11.79)	(12.73)
HANGINGSTONE OPERATING NETBACK(1) ($/bbl)	$ (8.54)	$ (35.34)

(1) Refer to “Advisories and Other Guidance” beginning on page 18 for additional information on Non-GAAP Financial Measures.

For the three months ended March 31, 2017, Athabasca averaged 8,552 bbl/d of bitumen production at Hangingstone compared to 7,029 bbl/d during the same period in the prior year. The Company achieved first oil at its Hangingstone Project during the third quarter of 2015 and continues to ramp-up the project toward its design capacity of 12,000 bbl/d which is anticipated in 2018.

During the quarter ended March 31 2017, the Hangingstone Operating Netback was $(8.54)/bbl, compared to $(35.34)/bbl during the three months ended March 31, 2016. The improvement in the Thermal Oil Operating Netback was primarily due to higher production volumes and a higher realized price for blended bitumen.

Compared to the same period in the prior year, operating expenses per bbl decreased by 17% to $24.85/bbl during the three months ended March 31, 2017. The decrease was primarily due to higher production which resulted in lower per-unit non-energy operating expenses which carry a high fixed component. The decline was partially offset by higher energy operating expenses during the first quarter of 2017 which increased as a result of higher natural gas prices. Operating expenses and transportation costs per bbl are expected to decrease as Hangingstone production increases toward design capacity.

Consolidated Thermal Oil Operating Results

Three months ended	March 31, 2017	March 31, 2016
VOLUMES		
Bitumen production (bbl/d)	23,316	7,029
Bitumen sales (bbl/d)	23,257	7,176
Blended bitumen sales (bbl/d)	33,680	10,175

Three months ended ($ Thousands, except volume and bbl amounts)		March 31, 2017		March 31, 2016
Blended bitumen sales	$	139,503	$	21,101
Cost of diluent		(77,949)		(16,356)
Total bitumen sales		61,554		4,745
Realized gain on commodity risk management contracts		2,291		—
Royalties		(1,405)		(25)
Operating expenses - non-energy		(26,937)		(16,063)
Operating expenses - energy		(10,456)		(3,420)
Transportation and marketing		(12,706)		(8,311)
Thermal Oil Operating Income(1)	$	12,341	$	(23,074)
REALIZED PRICE				
Blended bitumen sales ($/bbl)	$	46.02	$	22.79
Bitumen sales ($/bbl)	$	29.41	$	7.27
Realized gain on commodity risk management contracts ($/bbl)		1.09		—
Royalties ($/bbl)		(0.67)		(0.04)
Operating expenses - non-energy ($/bbl)		(12.87)		(24.60)
Operating expenses - energy ($/bbl)		(5.00)		(5.24)
Transportation and marketing ($/bbl)		(6.07)		(12.73)
THERMAL OIL OPERATING NETBACK(1) ($/bbl)	$	5.89	$	(35.34)

(1) Refer to "Advisories and Other Guidance" beginning on page 18 for additional information on Non-GAAP Financial Measures.

Thermal Oil Segment Income

Three months ended ($ Thousands)		March 31, 2017		March 31, 2016
Thermal Oil Operating Income(1)	$	12,341	$	(23,074)
Unrealized gain on commodity risk management contracts		7,214		—
Depletion and depreciation		(14,673)		(6,695)
Exploration expenses and other		(443)		(147)
THERMAL OIL SEGMENT INCOME (LOSS)	$	4,439	$	(29,916)

(1) Refer to "Advisories and Other Guidance" beginning on page 18 for additional information on Non-GAAP Financial Measures.

During the three months ended March 31, 2017, depletion and depreciation expense increased to $14.7 million compared to $6.7 million during the same period in the prior year. The increase in depletion and depreciation expense was primarily due to the Leismer Corner Acquisition.

Thermal Oil Capital Expenditures

Three months ended ($ Thousands)		March 31, 2017		March 31, 2016
Leismer Project(1)	$	5,332	$	—
Hangingstone Project		5,536		659
Other Thermal Oil exploration		—		257
TOTAL THERMAL OIL CAPITAL EXPENDITURES(2)	$	10,868	$	916

(1) Thermal Oil capital expenditures in the table above exclude the cost of the Leismer Corner Acquisition.
(2) For the three months ended March 31, 2017, Thermal Oil capital expenditures include $0.6 million in capitalized staff costs (March 31, 2016 - $0.4 million).

There were minimal capital expenditures in the Thermal Oil Division during the three months ended March 31, 2017 and 2016.

CORPORATE REVIEW

Liquidity and Capital Resources

Funding

Balance sheet strength and flexibility continues to remain a key priority for Athabasca and the Company's objective in managing capital is to maintain sufficient available reserves to meet its liquidity requirements at any point in time. The Company expects to achieve this objective through disciplined capital spending, an active commodity risk management program and by maintaining sufficient funds for anticipated short-term spending in cash, cash equivalent and short-term investment accounts and through available credit facilities.

As at March 31, 2017, Athabasca had $213.0 million of cash and cash equivalents (excluding restricted cash). The Company also had available credit of $103.4 million under its New Credit Facility and additional funding available through the capital-carry receivable from Murphy of $202.8 million (undiscounted).

Going forward, it is anticipated that Athabasca's Light Oil and Thermal Oil capital and operating activities, based on current business plans, will be funded through cash flow from operations, the capital-carry receivable, existing cash and cash equivalents and available credit facilities. Any significant acceleration of Light Oil development activities or future expansion of the Company's Thermal Oil projects could require additional funding which may include debt, equity, joint ventures or other external financing. The availability of any additional future funding will depend on, among other things, the current commodity price environment, operating performance, the Company's credit rating at the time and the current state of the equity and debt capital markets.

Indebtedness

As at ($ Thousands)		March 31, 2017		December 31, 2016
Senior Secured Second Lien Notes ("2022 Notes")(1)	$	599,490	$	—
Senior Secured Second Lien Notes ("2017 Notes")		—		550,000
Debt issuance costs		(46,788)		(21,664)
Amortization of debt issuance costs		675		17,873
TOTAL LONG-TERM DEBT	$	553,377	$	546,209

(1) As at March 31, 2017, the US dollar denominated 2022 Notes and associated debt issuance costs were translated into Canadian dollars at the period end exchange rate of US$1.00 = C$1.3322.

Throughout 2016 and early 2017, Athabasca repositioned its capital structure through a series of refinancing transactions which included:

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

The balance sheet refinancing provides multi-year funding certainty, a strong liquidity outlook and will allow the Company to advance its strategic objectives and maintain business flexibility.

2022 Notes

The 2022 Notes bear interest at a rate of 9.875% per annum, payable semi-annually, and have a term of five years maturing on February 24, 2022. At any time prior to February 24, 2019, Athabasca has the option to redeem the 2022 Notes at the make whole redemption price set forth in the 2022 Notes indenture. On or after February 24, 2019, Athabasca may redeem the 2022 Notes at the following specified redemption prices:

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

New Credit Facility

The New Credit Facility is a $120 million, 364 day committed facility available on a revolving basis until February 24, 2018, at which time it may be extended at the lenders' option. If the revolving period is not extended, the undrawn portion of the facility will be cancelled and any amount outstanding would be required to be repaid at the end of the non-revolving term, being February 24, 2019. The New Credit Facility is subject to a semi-annual borrowing base review of the Company's Light Oil and Thermal Oil properties with the first semi-annual review occurring in the second quarter of 2017. The borrowing base of the New Credit Facility will be based on the lender's evaluation of the Company's petroleum and natural gas reserves at the time and their commodity price outlook.

Amounts borrowed under the New Credit Facility bear interest at a floating rate based on the applicable Canadian prime rate, US base rate, LIBOR or bankers' acceptance rate, plus a margin of 4.5%. The Company also incurs a standby fee on the undrawn portion of the New Credit Facility of 1.125%. As at March 31, 2017, the Credit Facility had $16.6 million of letters of credit issued and outstanding.

Cash-Collateralized Letter of Credit Facility

Athabasca maintains a $110.0 million Bilateral Cash-Collateralized Letter of Credit Facility (the "Letter of Credit Facility") with a Canadian bank for issuing letters of credit to counterparties. The facility is available on a demand basis and letters of credit issued under the Letter of Credit Facility bear an issuance fee of 0.25%. Letters of credit issued under the Letter of Credit Facility are 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 cash-collateral account equivalent to 101% of the value of all letters of credit issued under the facility. As at March 31, 2017, Athabasca had $109.6 million in letters of credit issued under the Letter of Credit Facility.

Financing and Interest

Three months ended ($ Thousands)	March 31, 2017	March 31, 2016
Financing and interest expense on indebtedness	$ 14,691	$ 18,185
Amortization of debt issuance costs	5,098	1,855
Accretion of provisions	1,868	1,959
TOTAL FINANCING AND INTEREST	$ 21,657	$ 21,999

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

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

Amortization of debt issuance costs increased by $3.2 million to $5.1 million during the first quarter of 2017, compared to the first quarter of 2016, primarily due to the acceleration of remaining debt issuance costs on the 2017 Notes.

Foreign Exchange Gain (Loss), Net

Three months ended ($ Thousands)	March 31, 2017	March 31, 2016
Unrealized foreign exchange gain (loss)	$ (9,914)	$ 18,683
Realized foreign exchange gain (loss)	32	502
FOREIGN EXCHANGE GAIN (LOSS), NET	$ (9,882)	$ 19,185

During the first quarter of 2017, Athabasca became exposed to foreign currency risk on the principal and interest components of its newly issued US dollar denominated 2022 Notes and recognized a net foreign exchange loss in the quarter of $9.9 million. The loss was primarily due to an unrealized loss on the note principal as the average value of the Canadian dollar declined relative to the US dollar from the date the notes were issued to the end of the first quarter from 1.31:1 to 1.33:1.

During the three months ended March 31, 2016, Athabasca was exposed to foreign currency risk on the principal and interest components of it US dollar denominated Term Loan and recognized a net foreign exchange gain of $19.2 million primarily due to an unrealized gain on the loan principal as the average value of the Canadian dollar increased relative to the US dollar by 6% from 1.38:1 to 1.30:1.

Risk Management Contracts

Following the Leismer Corner Acquisition, Athabasca commenced a commodity risk management program designed to protect a base level of cash flow and support the Company's capital plans. The Company intends to hedge a minimum of 20,000 bbl/d of 2017 production and, as at March 31, 2017, had the following risk management contracts in place:

Instrument	Period	Volume	Average Price/ Unit
WCS fixed price swaps	February - December 2017	8,000 bbl/d	$ 52.66
WTI fixed price swaps	February - December 2017	4,000 bbl/d	$ 73.02
WTI/WCS differential fixed price swaps	February - December 2017	4,000 bbl/d	$ (20.25)
WTI/WCS differential fixed price swaps	April - December 2017	8,000 bbl/d	$ (19.68)
WTI costless collar	April - December 2017	1,000 bbl/d	$ 65.00 - 79.00

The following table summarizes the Company's net gain (loss) on risk management contracts during the three months ended March 31, 2017 and 2016:

Three months ended ($ Thousands)	March 31, 2017	March 31, 2016
COMMODITY CONTRACTS		
Unrealized gain on commodity risk management contracts	$ 7,214	$ —
Realized gain on commodity risk management contracts	2,291	—
FOREIGN EXCHANGE CONTRACTS		
Unrealized loss on foreign exchange risk management contracts	—	(20,860)
Realized gain on foreign exchange risk management contracts	—	911
GAIN (LOSS) ON RISK MANAGEMENT CONTRACTS (NET)	$ 9,505	$ (19,949)

During the three months ended March 31, 2017, Athabasca recognized a net gain on risk management contracts of $9.5 million primarily due to moderate declines in WTI and WCS benchmark prices from the effective date of its new commodity risk management contracts to the end of the first quarter of 2017.

During the three months ended March 31, 2016, Athabasca recognized a loss on risk management contracts of $19.9 million related to a foreign currency derivative put in place with respect to the Company's US dollar denominated Term Loan.

Commitments and Contingencies

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

($ Thousands)	2017	2018	2019	2020	2021	Thereafter	Total
Transportation	$ 73,463	$ 95,916	$ 65,903	$ 105,037	$ 102,946	$ 1,771,497	$ 2,214,762
Repayment of long-term debt(1)	—	—	—	—	—	599,490	599,490
Interest expense on long-term debt(1)	29,764	59,693	59,693	59,857	59,693	30,093	298,793
Office leases	1,839	2,452	2,452	2,452	2,452	9,356	21,003
Purchase commitments and other	5,702	2,976	—	—	—	—	8,678
TOTAL COMMITMENTS	$ 110,768	$ 161,037	$ 128,048	$ 167,346	$ 165,091	$ 2,410,436	$ 3,142,726

(1) The 2022 Notes and associated interest expense were translated into Canadian dollars at the March 31, 2017 exchange rate of US$1.00 = C$1.3322.

During the first quarter of 2017, Athabasca acquired firm service on the TMX Pipeline by entering into a long-term transportation service agreement with Trans Mountain Pipeline L.P. to deliver up to 20,000 bbl/d of the Company's blended bitumen from Edmonton, Alberta to Burnaby, B.C., starting in late 2019. Athabasca's minimum discounted take or pay commitment on the TMX Pipeline is approximately $345 million based on Athabasca's credit-adjusted discount rate of 10% ($1.1 billion undiscounted). The Company will be required to provide financial assurances, in the form of a letter of credit, of approximately $40 million beginning in May 2017. The TMX Pipeline commitment has been included in the above table.

In conjunction with the Leismer Corner Acquisition, Statoil reassigned to Athabasca its existing commitment for the transportation of blended bitumen on the Waupisoo pipeline. As at March 31, 2017, the remaining commitment was $63.7 million which expires at various times through 2021. A second transportation commitment was reassigned by Statoil to Athabasca for the transportation of diluent to the Leismer Project's central processing facility. As at March 31, 2017, the remaining commitment was $34.2 million which expires in the fourth quarter of 2018. The transportation commitments have been included in the above table.

Other Corporate Items

General and administrative ("G&A")

Three months ended ($ Thousands)		March 31, 2017		March 31, 2016
TOTAL GENERAL AND ADMINISTRATIVE	$	6,428	$	6,934
G&A per boe	$	2.67	$	5.77

During the three months ended March 31, 2017, Athabasca's general and administrative expenses per boe decreased 54% to $2.67/boe compared to the same period in the prior year. The declines were primarily due to higher production as a result the Leismer Corner Acquisition. The Company believes it has sufficient resources in place to support planned capital and operating activities over the next several years which is expected to result in further reductions to per unit general and administrative costs.

Stock-based compensation

During the three months ended March 31, 2017, stock-based compensation expense decreased from $1.6 million to $0.7 million compared to the same period in the prior year. The decrease was primarily due to lower fair values per award on 2016 grants and a lower average balance of units outstanding under the 2010 RSU compensation plan which had carried higher fair values per award relative to the other plans.

Gain on Revaluation of Provisions and Other

During the three months ended March 31, 2017, Athabasca incurred a gain of $6.7 million relating to a decline in the fair value of the Company's contingent payment obligation to Statoil from the date of closing of the Leismer Corner Acquisition on January 31, 2017 to the end of the first quarter of 2017. The contingent payment obligation is remeasured at each reporting period with any gains or losses recognized in net income. No amounts are currently payable with respect to the continent payment obligation.

Off Balance Sheet Arrangements

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

Equity Instruments

On January 31, 2017, Athabasca issued 100 million common shares to Statoil in respect of the Leismer Corner Acquisition. During the three months ended March 31, 2017, Athabasca also issued 0.3 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 April 26, 2017	
Common shares issued and outstanding	508,891,459
Convertible securities:	
Stock options	14,004,552
Restricted share units (2010 RSU Plan)	3,767,044
Restricted share units (2015 RSU Plan)	9,541,526
Performance share units	4,093,667
Deferred share units	1,606,731

For additional information regarding these compensation plans, refer to the consolidated financial statements of the Company for the year ended December 31, 2016.

OUTLOOK

The following tables reflect Athabasca's 2017 capital budget and corporate production guidance which includes the impact of the Leismer Corner Acquisition and refinancing activities completed during the first quarter of 2017:

2017 Capital Budget ($ millions)		Full year
Light Oil Division		
Greater Placid area (Montney)(1)	$	120
Greater Kaybob area (Duvernay)(2)		15
		135
Thermal Oil Division		
Leismer		54
Hangingstone		15
Other thermal		6
		75
Total capital expenditures(3)	$	210

(1) The Greater Placid area capital expenditures reflect Athabasca's 70% working interest.
(2) The Greater Kaybob area capital expenditures reflect Athabasca's 30% working interest, net of anticipated recovery from the capital-carry receivable.
(3) The 2017 capital budget of $210 million excludes capitalized staff costs of $5 million.

2017 Operational & Financial Guidance ($ millions, unless otherwise noted)		Full year
Light Oil (net)		
Production (boe/d)		6,500 - 7,500
Light Oil Operating Income(1)	$	75
Capital expenditures	$	135
Thermal Oil		
Bitumen production (bbl/d)(2)		29,000 - 32,500
Thermal Oil Operating Income(1)	$	100
Capital expenditures	$	75
Corporate		
Production (boe/d)(2)		36,000 - 40,000
Liquids weighting (%)		90%
Funds Flow from Operations(1)	$	90
Commodity assumptions		
WTI (US$/bbl)	$	52.00
Edmonton Par (C$/bbl)	$	65.00
Western Canadian Select (C$/bbl)	$	50.00
AECO Gas (C$/mcf)	$	2.75
FX (US$/C$)		0.75

(1) Refer to “Advisories and Other Guidance” beginning on page 18 for additional information on Non-GAAP Financial Measures.
(2) Production guidance reflects a January 31, 2017 closing date for the Leismer Corner Acquisition with the Leismer Project's volumes reported from February - December 2017.

Light Oil Division

Athabasca’s 2017 Light Oil capital budget is unchanged at $135 million ($120 million for Placid Montney and $15 million for Duvernay, net of capital carry) with production guidance of 6,500 - 7,500 boe/d and production is expected to reach 10,000 boe/d before the end of the year. Athabasca plans to reassess its Montney capital budget for the second half of 2017 mid-year.

Thermal Oil Division

The Company's revised 2017 Thermal Oil budget of $75 million consists of $54 million at Leismer, $15 million at Hangingstone and an additional $6 million for maintaining Athabasca’s long-dated thermal leases. The Leismer capital budget was reduced by $30 million as a result of strong well pair performance and prior investment in sustaining infill wells. Athabasca's Thermal Oil production guidance remains unchanged at 29,000 - 32,500 bbl/d.

SUMMARY OF QUARTERLY RESULTS

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

	2017	2016				2015		
($ Thousands, except share and per barrel amounts)	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	51.91	49.29	44.94	45.59	33.45	42.18	46.43	57.94
WTI (C$/bbl)	68.52	65.56	58.87	58.81	45.83	56.52	60.82	71.27
Western Canadian Select (C$/bbl)	49.34	46.61	41.01	41.62	26.30	36.86	43.29	71.24
Edmonton Par (C$/bbl)	63.87	61.59	54.66	54.78	40.67	52.85	56.17	67.63
Edmonton Condensate (C5+) (C$/bbl)	68.73	63.38	55.31	56.80	46.32	54.52	56.94	69.81
NYMEX Henry Hub (US$/MMBtu)	3.32	2.98	2.81	1.95	2.09	2.27	2.80	2.64
AECO (C$/GJ)	2.55	2.93	2.20	1.32	1.74	2.33	2.75	2.53
Foreign exchange (CAD : USD)	1.32	1.33	1.31	1.29	1.37	1.34	1.31	1.23
LIGHT OIL DIVISION								
Sales volumes (boe/d)	3,421	3,337	3,018	5,743	6,319	5,873	5,145	5,459
Realized price ($/boe)	38.97	35.99	29.84	26.93	21.73	27.39	31.34	34.43
Revenues ($)[2]	11,607	10,607	8,091	13,936	12,440	17,624	14,043	17,666
Light Oil Operating Income ($)[1]	6,863	6,152	5,511	7,215	4,908	10,551	6,096	10,689
Light Oil Operating Netback ($/boe)[1]	22.28	20.04	19.85	13.80	8.53	19.50	12.88	21.51
Capital expenditures ($)	77,646	62,003	18,920	5,518	30,658	50,921	31,465	14,959
Recovery of the capital-carry receivable ($)	(10,680)	(52)	(4,286)	(1,474)	—	—	—	—
THERMAL OIL DIVISION								
Bitumen production (bbl/d)[3][4]	23,316	8,293	8,830	5,358	7,029	5,708	2,105	—
Sales volumes (bbl/d)[3][4]	23,257	8,015	9,744	4,463	7,176	4,096	1,792	—
Realized bitumen price ($/bbl)[5]	29.41	31.46	28.56	24.51	7.27	21.23	17.54	—
Revenues ($)[2]	138,098	44,058	45,124	19,386	21,076	15,033	6,145	—
Thermal Oil Operating Income (Loss) ($)[1][4][5]	12,341	(4,719)	(6,088)	(11,915)	(23,074)	(18,166)	(12,146)	—
Thermal Oil Operating Netback ($/bbl)[1][4][5]	5.89	(6.41)	(6.80)	(29.33)	(35.34)	(48.22)	(73.67)	—
Capital expenditures	10,868	4,088	3,754	2,187	916	2,257	9,366	33,118
OPERATING RESULTS								
Cash Flow from Operations ($)	(52,896)	(19,656)	(18,990)	5,759	(38,017)	(54,496)	(17,933)	8,576
Funds Flow from Operations ($)[1]	(1,649)	(16,867)	(15,778)	(27,304)	(39,982)	(30,141)	(24,223)	5,085
Net income (loss) ($)	(29,162)	(779,405)	(33,032)	(59,169)	(65,129)	(604,375)	(38,241)	(29,044)
Net income (loss) per share - basic ($)	(0.06)	(1.92)	(0.08)	(0.15)	(0.16)	(1.50)	(0.09)	(0.07)
BALANCE SHEET ITEMS								
Cash and cash equivalents ($)	212,999	650,301	535,477	447,282	493,510	559,487	671,447	582,396
Short-term investments ($)	—	—	35,000	25,533	—	—	—	—
Restricted cash ($)	113,823	107,012	103,827	101,652	—	—	—	—
Capital-carry receivable (discounted) ($)[6]	183,745	191,174	188,448	188,742	—	—	—	—
Promissory notes ($)[6]	—	—	—	133,892	133,892	133,892	133,892	283,892
Assets held for sale ($)	—	—	—	—	466,159	—	—	—
Total assets ($)	2,524,187	2,257,887	3,017,285	3,028,938	3,394,367	3,462,442	4,160,344	4,173,704
Long-term debt ($)[6]	553,377	546,209	545,126	544,042	820,478	838,205	827,773	807,167
Shareholders' equity ($)	1,695,582	1,557,097	2,333,523	2,363,396	2,419,651	2,482,140	3,085,499	3,119,224

(1) Refer to "Advisories and Other Guidance" beginning on page 18 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) Q3 2015 includes capitalized volumes.
(4) Athabasca capitalized initial operating results of the Hangingstone Project until it 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.
(5) Figures include the impact of realized gains on commodity risk management contracts.
(6) Balances include the current and long-term portions as reported in the consolidated balance sheets.

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

ACCOUNTING POLICIES AND ESTIMATES

During the three months ended March 31, 2017, there were no changes to Athabasca's accounting policies or use of estimates in the preparation of the consolidated financial statements and the notes thereto that had a material impact to the consolidated financial statements. Refer to the December 31, 2016 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 "Funds Flow from Operations", "Light Oil Operating Income", "Light Oil Operating Netback", "Thermal Oil Operating Income" and "Thermal Oil Operating Netback" financial measures contained in this MD&A do not have standardized meanings which are prescribed by IFRS and they are considered to be non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers and should not be considered in isolation with measures that are prepared in accordance with IFRS.

The following table reconciles cash flow from operating activities in the consolidated financial statements for the three months ended March 31, 2017 and 2016 to Funds Flow from Operations:

Year ended ($ Thousands)	March 31, 2017	March 31, 2016
Cash flow from operating activities	$ (52,896)	$ (38,017)
Acquisition expenses and other	7,647	—
Changes in non-cash working capital	39,081	(3,772)
Settlement of provisions	4,519	1,448
Other items	—	359
FUNDS FLOW FROM OPERATIONS	$ (1,649)	$ (39,982)

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) is 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 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 Light Oil Operating Netback measures allow management and others to evaluate the production results from the Company's Light Oil assets. The table on page 7 reconciles Light Oil Operating Income to *Note 12 - Segmented Information* in the consolidated financial statements for the three months ended March 31, 2017.

The Operating Income and Operating Netback measures in this MD&A with respect to the Leismer Project and Hangingstone Project are calculated by subtracting the cost of diluent blending, royalties, operating expenses and transportation expenses from blended bitumen sales. The consolidated Thermal Oil Operating Income and Operating Netback measures also include realized gains on commodity risk management contracts. The Thermal Oil Operating Netback measure is presented on a per bbl basis. The Thermal Oil Operating Income and the Thermal Oil Operating Netback measures allow management and others to evaluate the production results from the Company's Thermal Oil assets. The table on page 10 reconciles Thermal Oil Operating Income to *Note 12 - Segmented Information* in the consolidated financial statements for the three months ended March 31, 2017.

Risk Factors

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

Operational risks
- the performance of the Company's assets;
- Athabasca's 2017 exploration and development budget and Athabasca's capital expenditure programs;
- failure to realize anticipated benefits of acquisitions or divestments, including the Leismer Corner Acquisition;
- uncertainties inherent in estimating quantities of Proved Reserves, Probable Reserves and Contingent Resources;

- the timing of certain of Athabasca's operations and projects, including the commencement of its planned Thermal Oil division development projects, the exploration and development of Athabasca's Light Oil assets and the levels and timing of anticipated production;
- the timing of the project activities related to the Hangingstone Project included the timing of the ramp-up of Hangingstone Project production to nameplate capacity;
- dependence upon Murphy as a working interest participant in its Light Oil assets and as operator of the Greater Kaybob assets;
- risks and uncertainties inherent in Athabasca's operations, including those related to exploration, development and production of petroleum, natural gas and oil sands reserves and resources;
- risks related to gathering and processing facilities and pipeline systems;
- reliance on third party infrastructure;
- risks associated with events of force majeure;
- expiration of leases and permits or the failure of Athabasca or the holder of certain licenses, leases or permits to meet specific requirements of such licenses, leases or permits;

Planning risks

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

Financial and market risks

- general economic, market and business conditions in Canada, the United States and globally;
- future market prices for crude oil, natural gas, condensate and bitumen blend;
- Athabasca's projections of commodity prices, costs and netbacks;
- the substantial capital requirements of Athabasca's projects and the Company's ability to raise capital;
- the potential for future joint venture arrangements;
- insurance risks;
- hedging risks;
- variations in foreign exchange and interest rates;
- risks related to the New Credit Facility, the Letter of Credit Facility and the 2022 Notes;
- risks related to the Common Shares.

Legal and compliance risks

- the regulatory framework governing royalties, taxes, environmental matters and foreign investment in the jurisdictions in which Athabasca conducts and will conduct its business;
- actions taken by the new American administration, including the potential renegotiation of the terms of the North American Free Trade Agreement, the withdrawal of the United States from the Trans-Pacific Partnership and the imposition of taxes on the importation of goods into the United States;
- aboriginal claims;
- risks associated with establishing and maintaining systems of internal controls;
- inaccuracy of forward-looking information;

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

Forward Looking Information

This MD&A contains forward-looking information that involves various risks, uncertainties and other factors. All information other than statements of historical fact is forward-looking information. The use of any of the words "anticipate," "plan," "continue", "estimate", "expect", "may", "will", "project", "target", "should", "believe", "predict", "pursue" and "potential" and similar expressions are intended to identify forward-looking information. The forward-looking information is not historical fact, but rather is based on the Company's current plans, objectives, goals, strategies, estimates, assumptions and projections about the Company's industry, business and future financial results. This information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. No assurance can be given that these expectations will prove to be correct and such forward-looking information included in this MD&A should not be unduly relied upon. This information speaks only as of the date of this MD&A. In particular, this MD&A may contain forward-looking information pertaining to the following: the Company's five-year growth outlook and that such growth outlook is fully funded; the benefits expected to be realized by the Company from offering of 2022 Notes and the New Credit Facility; the benefits expected to be realized by the Company from the Leismer Corner Acquisition; the timing by which the Corporation expects to achieve sustainable free cash flow generation, cash and cash equivalents and liquidity, for certain future periods; expectations with respect to future production hedging levels; estimates of 2017 corporate, Thermal Oil and Light Oil production levels and base decline rates; estimates of future depletion rates on the Hangingstone Project; the expectation that operating and transportation expenses will decrease at Hangingstone; the in-service date of the TMX Pipeline and the benefits Athabasca expects to realize by having capacity thereon; estimates of 2017 funds flow from operations, operating income and capital expenditures; the capability of the Company's five-year development outlook to deliver potential growth in per share production; the estimated impact of the Royalty on the economics of future expansion phases and development projects; future drilling and completion plans; the timing for achievement of name plate capacity at the Hangingstone Project the timing of facilities construction and in service dates and the capacity thereof; the timing of well spudding and completion operations and wells coming on-stream; the Company's expected flexibility in its pace of development; the Company's plans for, and results of, exploration and development activities; the Company's estimated future commitments; Athabasca's continued balance-sheet strength; the Company's business and financing plans and strategies; expectations regarding the 2017 capital budget; the Company's anticipated sources of funding for 2017 and beyond; the Company's estimate future minimum capital commitments; the future allocation of capital; and other matters.

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

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

Actual results could differ materially from those anticipated in this forward-looking information as a result of the risk factors set forth in the Company's most recent AIF available on SEDAR at www.sedar.com, including, but not limited to: weakness in the oil and gas industry; fluctuations in market prices for crude oil, natural gas and bitumen blend; general economic, market and business conditions in Canada, the United States and globally; insurance risks; claims made in respect of Athabasca's operations, properties or assets; the substantial capital requirements of Athabasca's projects and the ability to obtain financing for Athabasca's capital requirements; global financial uncertainty; failure to realize anticipated benefits of acquisitions or divestments; risks related to hydraulic fracturing; factors affecting potential profitability; failure to obtain regulatory approvals or maintain compliance with regulatory requirements; extent of, and cost of compliance with, government laws and regulations and the effect of changes in such laws and regulations from time to time; risks relating to changing royalty regimes; additional funding requirements and liquidity risk; variations in foreign exchange and interest rates; environmental risks and hazards and the cost of compliance with environmental regulations, including the licensee liability rating program, seismic activity regulations, 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, risks associated with events of force majeure; risks related to the New Credit Facility, the Letter of Credit Facility and the 2022 Notes; geopolitical risks; uncertainties inherent in estimating quantities of reserves and resources; contractual counterparty risks and operational dependence; risks related to future acquisition and joint venture activities; risks and uncertainties inherent in Athabasca's operations, including those related to exploration, development and production of petroleum, natural gas and oil sands reserves and resources, including the production of oil sands reserves and resources using SAGD, TAGD or other in-situ recovery technologies; failure to meet development schedules and potential cost overruns; aboriginal claims; reliance on, competition for, loss of, and failure to attract key personnel; financial assurance covenants and collateral requirements under the Company's pipeline transportation agreements; risks related to gathering and processing facilities and pipeline systems; availability of drilling and related equipment and limitations on access to Athabasca's assets; increases in operating costs could make Athabasca's projects uneconomic; the effect of diluent and natural gas supply constraints and increases in the costs thereof; costs of new technologies; alternatives to and changing demand for petroleum products; gas over bitumen issues affecting operational results; risks related to Athabasca's filings with taxation authorities, including the risk of tax related reviews and reassessments; failure to accurately estimate abandonment and reclamation costs; the potential for management estimates and assumptions to be inaccurate; long-term reliance on third parties; reliance on third party infrastructure; seasonality; risks associated with establishing and maintaining systems of internal controls; competition for, among other things, capital, the acquisition of reserves and resources, export pipeline capacity and skilled personnel; expiration of leases and permits or the failure of Athabasca or the holder of certain licenses, leases or permits to meet specific requirements of such licenses, leases or permits; breaches of confidentiality; inaccuracy of forward-looking information; expansion into new activities; risks related to the Common Shares.

In addition, information and statements in this MD&A relating to "Reserves" and "Resources" are deemed to be forward-looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and that the reserves and resources described can be profitably produced in the future. Certain assumptions related to the Company's Reserves and Resources are contained in the reports of GLJ and D&M evaluating Athabasca's Proved Reserves, Probable Reserves and Contingent Resources as at December 31, 2016 (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, 2016. There are numerous uncertainties inherent in estimating quantities of bitumen, crude oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth above are estimates only. In general, estimates of economically recoverable reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially. For those reasons, estimates of the economically recoverable reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. There is no certainty that it will be commercially viable to produce any portion of the resources. Reserves figures described herein have been rounded to the nearest MMbbl or MMboe. Contingent Resources described herein have been rounded to the nearest billion barrels. For additional information regarding the consolidated reserves and resources of the Company as evaluated by GLJ in the GLJ Report and by D&M in the D&M Report, please refer to the Company's AIF that is available on SEDAR at www.sedar.com.

Additionally, the reserves and resources data relating to the Leismer and Corner assets is based on a report prepared by GLJ dated January 5, 2017 reporting the reserves attributable to such assets as at December 31, 2016, and was prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and the COGE Handbook.

Oil and Gas Information

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

Drilling Locations

The 1,500 Duvernay drilling locations referenced on page 1 of this MD&A include: 31 proved undeveloped or non-producing locations and 42 probable undeveloped locations for a total of 73 undeveloped booked locations with the balance being unbooked locations. The 150-200 Montney drilling locations referenced on page 1 of this MD&A include: 34 proved undeveloped and 12 probable undeveloped locations, for a total of 46 undeveloped booked locations with the balance being unbooked locations. Proved undeveloped locations and probable undeveloped locations are booked and derived from the Company's most recent independent reserves evaluation as prepared by GLJ as of December 31, 2016 and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal management estimates. Unbooked locations do not have attributed reserves or resources (including contingent or prospective). Unbooked locations have been identified by management as an estimation of Athabasca's multi-year drilling activities expected to occur over the next two decades based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, oil and natural gas prices, provincial fiscal and royalty policies, costs, actual drilling results and additional reservoir information that is obtained and other factors.

Definitions

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

"**Contingent Resources**" are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include such factors as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "Contingent Resources" the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources may be divided into the following project maturity sub-classes: "Development Pending" is assigned to Contingent Resources for a particular project where resolution of the final conditions for development is being actively pursued (high chance of development); "Development On Hold" is assigned to Contingent Resources for a particular project where there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator; "Development Unclarified" is assigned to Contingent Resources for a particular project where evaluation is incomplete and there is ongoing activity to resolve any risks or uncertainties or which require significant further appraisal to clarify potential for development and where contingencies have yet to be defined; "Development Not Viable" is assigned to Contingent Resources for a particular project where no further data acquisition or evaluation is currently planned and there is a low chance of development. As at December 31, 2016, 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.

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

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

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

Abbreviations

AECO	Physical storage and trading hub for natural gas on the TransCanada Alberta transmission system which is the delivery point for various benchmark Alberta index prices.
bbl	barrel
bbl/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
C$	Canadian Dollars
COGE	Canadian Oil and Gas Evaluation
GAAP	Generally Accepted Accounting Principles
G&A	General and administrative
LIBOR	London interbank offered rate
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMbbl	millions of barrels
MMboe	millions of barrels of oil equivalent
MMBtu	million British thermal units
NYMEX	New York Mercantile Exchange
OPEC	Organization of the Petroleum Exporting Countries
SAGD	steam assisted gravity drainage
SOR	Steam to oil ratio
TAGD	thermal assisted gravity drainage
US$	United States Dollars
WCS	Western Canadian Select