Management's Discussion and Analysis

December 31, 2015

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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 March 10, 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. 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 30 of this MD&A. See "Reserves and Resource information" on page 31 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 33 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. Initial developments have been focused in Saxon/Placid (the "Greater Placid area") and Kaybob ("Greater Kaybob area") near the town of Fox Creek, Alberta. Athabasca has 25,000 gross acres of commercially prospective Montney lands within the Greater Placid area and has identified a potential inventory of more than 160[(1)] gross drilling locations. Athabasca also has over 200,000 gross acres of commercially prospective Duvernay lands in Greater Kaybob area at various stages of delineation and development where the Company has identified a potential inventory of more than 1,000[(1)] gross drilling locations. Development to date has resulted in the booking of approximately 65 MMboe[(2)(3)] of Proved plus Probable Reserves in Athabasca's Light Oil Division as of December 31, 2015. Athabasca exited the fourth quarter of 2015 with December average production of approximately 7,740 boe/d in the Light Oil Division.

In the first quarter of 2016, Athabasca announced that it had entered into an agreement with Murphy Oil Company Ltd. (the wholly owned Canadian subsidiary of Murphy Oil Corporation, "Murphy") to form a strategic joint venture to develop the Duvernay and Montney Formations in the Greater Kaybob and Greater Placid areas. As part of the transaction, the Company will sell an operated 70% of its interest in the Greater Kaybob area and a non-operated 30% of its interest in the Greater Placid area[(3)].

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. During the third quarter of 2015, the Company produced its first significant production at Hangingstone Project 1, Athabasca's first thermal oil project which is anticipated to reach 12,000 bbl/d in late 2016 ("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. Athabasca exited the fourth quarter of 2015 with December average production of approximately 7,460 boe/d in the Thermal Oil Division.

Athabasca's exploration areas consist of the Dover West Leduc Carbonates, Dover West Sands and Birch areas. 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 27 for additional information regarding the Company's drilling locations.
(2) Based on the reports of Athabasca's independent reserve evaluators effective December 31, 2015. Refer to page 31 and the AIF for additional important information about the Company's Reserves and Contingent Resources.
(3) In the first quarter of 2016, Athabasca entered into the Murphy Transaction which is anticipated to result in the sale of approximately 38 MMboe of Proved plus Probable Reserves from the Light Oil Division to Murphy. The transaction is expected to close in the second quarter of 2016, subject to the parties meeting certain conditions.

SELECTED FINANCIAL INFORMATION

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

($ Thousands, except volume, boe and share amounts)	December 31, 2015	December 31, 2014	December 31, 2013
CONSOLIDATED PRODUCTION			
Petroleum and natural gas volumes (boe/d)[1]	7,560	6,120	6,397
LIGHT OIL DIVISION			
Petroleum and natural gas sales volumes (boe/d)	5,587	6,120	6,397
Light Oil Operating Income[2]	$ 33,928	$ 78,734	$ 75,258
Light Oil Operating Netback[2] ($/boe)	$ 16.63	$ 35.24	$ 32.22
Capital expenditures	$ 175,977	$ 199,938	$ 282,050
THERMAL OIL DIVISION			
Bitumen production (bbl/d) (including capitalized volumes)[1]	1,973	—	—
Bitumen sales volumes (bbl/d)[1]	1,526	—	—
Thermal Oil Operating Loss[2][3]	$ (30,200)	$ —	$ —
Thermal Oil Operating Netback ($/bbl)[2][3]	$ (55.74)	$ —	$ —
Capital expenditures	$ 114,150	$ 416,967	$ 447,819
CASH FLOW AND FUNDS FLOW			
Cash flow from operating activities	$ (67,826)	$ 18,177	$ (11,513)
Cash flow from operating activities per share (basic and diluted)	$ (0.17)	$ 0.05	$ (0.03)
Funds Flow from Operations[2]	$ (47,003)	$ 23,782	$ (3,739)
Funds Flow from Operations per share (basic and diluted)[2]	$ (0.12)	$ 0.06	$ (0.01)
NET LOSS AND COMPREHENSIVE LOSS			
Net loss and comprehensive loss	$ (696,771)	$ (227,558)	$ (126,138)
Net loss and comprehensive loss per share (basic and diluted)	$ (1.73)	$ (0.57)	$ (0.32)
SHARES OUTSTANDING			
Weighted average shares outstanding (basic and diluted)	403,214,050	401,512,412	400,111,681
FINANCING AND DIVESTITURES			
Net proceeds from sale of Investments	$ 450,000	$ 601,304	$ 173,894
Net proceeds from sale of oil and gas assets	1,788	59,974	—
Net proceeds from (repayment of) long-term debt	(2,921)	235,394	—
	$ 448,867	$ 896,672	$ 173,894

(1) For the year ended December 31, 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 period averaged over 365 days.
(2) Refer to "Advisories and Other Guidance" beginning on page 27 for additional information on Non-GAAP Financial Measures.
(3) Hangingstone Project 1 was ready for use in the manner intended by management on August 1, 2015. Operating results prior to August 1, 2015 have been capitalized and excluded from the calculation of the Thermal Oil Operating Loss and Netback. Negative Operating Netbacks are customary during ramp-up of a SAGD project as revenues from lower initial production is more than offset by operating and transportation costs which are largely fixed in nature regardless of production volumes. Athabasca anticipates that operating costs per barrel from Project 1 will continue to materially improve as production increases.

As at ($ Thousands)	December 31, 2015	December 31, 2014	December 31, 2013
BALANCE SHEET ITEMS			
Cash and cash equivalents	$ 559,487	$ 531,475	$ 298,995
Short-term investments	$ —	$ 47,618	$ 23,795
Promissory notes - short-term portion	$ 133,892	$ 450,000	$ —
Promissory notes - long-term portion	$ —	$ 133,892	$ —
Assets held for sale	$ —	$ —	$ 1,219,523
Total assets	$ 3,462,442	$ 4,297,803	$ 4,342,325
Long-term debt	$ 838,205	$ 786,649	$ 533,210
Net debt[1]	$ 154,711	$ (123,625)	$ (884,970)
Shareholders' equity	$ 2,482,140	$ 3,164,186	$ 3,373,957

(1) Refer to "Advisories and Other Guidance" beginning on page 27 for additional information on Non-GAAP Financial Measures.

HIGHLIGHTS

Corporate

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

  Murphy will pay approximately $250.0 million in cash to Athabasca on the transaction closing date. Additional consideration of approximately $225.0 million will be in the form of a capital carry in the Greater Kaybob area whereby Murphy will fund 75% of Athabasca's share of development capital up to a maximum five year period. Expected gross capital investment over this time period is planned to be approximately $1.0 billion with flexibility on spending as commodity prices recover. The effective date of the Murphy Transaction is January 1, 2016 and is anticipated to close in the second quarter of 2016, subject to the parties meeting certain conditions.

- For the year ended December 31, 2015, Athabasca produced 7,560 boe/d from the Company's Light Oil and Thermal Oil Divisions, compared to 6,120 boe/d during the same period in the prior year. The net increase in production volumes in 2015 was primarily due to commencement of production from Hangingstone Project 1, the Company's first thermal oil project. Athabasca exited the fourth quarter of 2015 with production of approximately 15,200 boe/d (December average) which exceeded the Company's exit guidance of 12,000 boe/d - 15,000 boe/d.

- For the year ended, December 31, 2015, Athabasca spent $291.7 million on capital expenditures, a 9% reduction compared to the capital budget guidance of $322 million provided by the Company on November 4, 2015 primarily due to cost savings associated with the 2015/16 Light Oil drilling program.

- As at December 31, 2015, Athabasca had cash and cash equivalents of $559.5 million and a promissory note of $133.9 million due in the third quarter of 2016. Following the closing of the Murphy Transaction, Athabasca is anticipated to have approximately $900 million of liquidity (including cash, cash equivalents and the promissory note).

Light Oil Division

- For the three months ended December 31, 2015, Athabasca produced 5,873 boe/d (50% liquids) in the Light Oil Division, a 3% decrease compared to 6,035 boe/d (52% liquids) during the same period in the prior year. For the year ended December 31, 2015, Athabasca produced 5,587 boe/d (49% liquids), a 9% decrease compared to 6,120 boe/d (51% liquids) during the same period in the prior year. Athabasca exited the fourth quarter of 2015 with December average production of approximately 7,740 boe/d achieving the Company's exit guidance of 7,000 boe/d - 8,000 boe/d.

- For the three months ended December 31, 2015, Athabasca's Light Oil Operating Netback[(1)] was $19.50/boe, compared to $22.38/boe in the prior year. For the year ended December 31, 2015, Athabasca's Light Oil Operating Netback[(1)] was $16.63/boe, compared to $35.24/boe during the same period in the prior year. The decreases in the Light Oil Operating Netback[(1)] were primarily due to lower underlying commodity prices.

- Athabasca spent $176.0 million in the Light Oil Division during the year ended December 31, 2015 primarily to drill 12 and complete six Duvernay wells in the Greater Kaybob area. The Company also drilled four and completed two Montney wells in the Greater Placid area. During the fourth quarter of 2015, Athabasca also commenced construction of a pipeline that will connect the Company's Placid development in the Greater Placid area to its existing delivery infrastructure. Athabasca anticipates the pipeline to be completed in the first half of 2016.

- Following a successful 2015 drilling program, Athabasca's Light Oil Division has Proved plus Probable Reserves of 65 MMBoe[(2)], an increase of 30% compared to the prior year.

(1) Refer to "Advisories and Other Guidance" beginning on page 27 for additional information on Non-GAAP Financial Measures.
(2) Based on the reports of Athabasca's independent reserve evaluators effective December 31, 2015. Refer to page 31 and the AIF for additional important information about the Company's Reserves and Contingent Resources.

Thermal Oil Division

- Athabasca spent $114.2 million in the Thermal Oil Division during the year ended December 31, 2015 primarily on start-up operations at Hangingstone. Athabasca completed Project 1 during the first quarter of 2015 and achieved first oil in Jul, in line with management's expectations. By the end of year, 21 of the 25 well pairs were converted to production. Third party construction of the diluent and dilbit transportation facilities was completed with commissioning during the second and fourth quarters, respectively.

- For the three months ended December 31, 2015, Athabasca produced 5,708 bbl/d in the Thermal Oil Division. For the year ended December 31, 2015, production averaged 1,973 bbl/d (averaged over 365 days). Athabasca exited the fourth quarter of 2015 with production of approximately 7,460 bbl/d (December average) exceeding the Company's exit guidance of 5,000 - 7,000 bbl/d.

INDEPENDENT RESERVES AND RESOURCES EVALUATION

The Company's qualified independent reserve evaluators, GLJ Petroleum Consultants Ltd. ("GLJ") and DeGoyler and MacNaughton Canada Limited ("D&M"), completed independent reserve and resource evaluations effective December 31, 2015. The Company's light oil, natural gas and natural gas liquids reserves are located in the Greater Placid and Greater Kaybob areas within the Company's Light Oil Division. The Company's bitumen reserves are located in the Hangingstone area of the Company's Thermal Oil Division.

Reserves

At December 31, 2015, the Company had 290 MMbbl of Proved plus Probable Reserves. The following table shows the Company's reserves by division and project area:

	December 31, 2015		December 31, 2014	
Reserves [1]	Proved	Proved plus Probable	Proved	Proved plus Probable
Light Oil Division (MMboe)[2]	27	65	12	50
Hangingstone (MMbbl)	95	225	51	226
Dover West sands (MMbbl)	—	—	—	87
Thermal Oil Division (MMbbl)	95	225	51	313
Consolidated Reserves (MMboe)[2]	122	290	63	362

(1) Refer to "Advisories and Other Guidance" beginning on page 27 for important information regarding the Company's Reserve estimates. Some totals may not add due to rounding.
(2) In the first quarter of 2016, Athabasca entered into the Murphy Transaction which is anticipated to result in the sale of approximately 38 MMboe of Proved plus Probable Reserves from the Light Oil Division to Murphy. The transaction is expected to close in the second quarter of 2016.

In the Light Oil Division, Proved Reserves increased by 125% from 12 MMboe to 27 MMboe, and Proved plus Probable Reserves increased by 30% from 50 MMboe to 65 MMBoe for the year ended December 31, 2015. The increases were primarily due to continued delineation drilling and development of the Duvernay and Montney formations within Greater Kaybob and Greater Placid areas during the year.

In the Thermal Oil Division, Proved Reserves increased from 51 MMbbl to 95 MMbbl in the Hangingstone area during the year ended December 31, 2015. The increase was primarily due to the Environmental Impact Assessment ("EIA") associated with the Company's 70,000 bbl/d Hangingstone Expansion project being deemed technically complete by the Alberta Energy Regulator during the year. Athabasca anticipates receiving final regulatory approval for the Hangingstone Expansion in 2016.

In response to the current environment, Athabasca deferred its anticipated development for a 12,000 bbl/d Dover West Sands thermal oil project beyond its previous five-year development plan and the Company re-classified 87 MMbbl of Probable Reserves associated with the project to Contingent Resources.

Contingent Resources

As at December 31, 2015, Athabasca had 0.6 billion risked barrels (0.8 billion unrisked barrels) of Best Estimate Contingent Resources in the Hangingstone area which included 0.3 billion barrels of risked Contingent Resources on hold and 0.2 billion barrels of risked pending Contingent Resources. In the Dover West Sands area, Athabasca had 1.6 billion risked barrels (3.0 billion unrisked barrels) of Best Estimate Contingent Resources of which 0.1 billion barrels were risked on hold Contingent Resources and the remainder were unclarified Contingent Resources. In the Birch area, Athabasca had 1.3 billion risked barrels (2.1 billion unrisked barrels) of Best

Estimate Contingent Resources, consisting of 1.0 billion barrels of risked on hold and 0.3 billion barrels of risked unclarified resources. Refer to advisories and other guidance starting on page 27 and the Company's AIF dated March 10, 2016 for further details. Figures above may not add due to rounding.

RESULTS OF OPERATIONS

Business Environment

The following table summarizes the key commodity price benchmarks for the years ended December 31, 2015 and 2014:

Year ended (annual average)	December 31, 2015	December 31, 2014
Crude Oil:		
West Texas Intermediate (WTI) (US$/bbl)	$ 48.80	$ 93.00
Western Canadian Select (WCS) (C$/bbl)	$ 44.82	$ 81.10
Differential - WTI vs. WCS (US$/bbl)	$ (13.52)	$ (19.40)
Edmonton Par (C$/bbl)	$ 57.11	$ 94.49
Edmonton Condensate (C5+) (C$/bbl)	$ 59.17	$ 100.42
Natural gas:		
NYMEX Henry Hub (US$/MMBtu)	$ 2.67	$ 4.39
AECO (C$/GJ)	$ 2.55	$ 4.25
Foreign exchange:		
CAD : USD	1.28	1.10

The price of WTI for crude oil sales at Cushing, Oklahoma is the primary benchmark for crude oil production in North America. The price Athabasca receives for its oil production in both its Light Oil and Thermal Oil Divisions is primarily driven by the price of WTI, adjusted to Western Canada. The WTI price is also used by the Province of Alberta for determining royalty rates on Athabasca's bitumen sales. For the year ended December 31, 2015, the WTI price declined by US$44.20/bbl, or 48%, compared to the prior year primarily due to continuing global over-supply of petroleum and natural gas production.

The WCS price at Hardisty, Alberta is the primary benchmark for Athabasca's blended bitumen sales. The WCS price normally trades at a higher differential to the WTI price compared to lighter crude oil products. For the years ended December 31, 2015 and 2014, WCS traded at an average differential below the WTI benchmark price of US$13.52/bbl and $19.40/bbl, respectively.

During the year ended December 31, 2015, the value of the Canadian dollar declined relative to the US dollar by 16%. Since North American crude oil prices are primarily set by U.S. benchmark prices, declines in the value of the Canadian dollar relative to the US dollar partially offset the negative impact of declining oil prices.

The Edmonton Par price and Edmonton Condensate (C5+) prices are the primary benchmarks for crude oil, condensate and natural gas liquids sales in the Company's Light Oil Division. In the Thermal Oil Division, the Edmonton Condensate (C5+) price is the primary benchmark for diluent purchases which Athabasca consumes in the blending process at Project 1 in order to deliver produced bitumen to the market. For the year ended December 31, 2015, the average Edmonton par price declined by $37.38/bbl compared to the prior year. For the year ended December 31, 2015, the average Edmonton Condensate (C5+) price declined by $41.25/bbl compared to the prior year.

For the year ended December 31, 2015, the AECO price was $2.55/GJ (2014 - $4.25/GJ). In the Thermal Oil Division, the AECO price is the primary benchmark for natural gas purchases consumed by Athabasca in order to generate steam which is used for the SAGD recovery process. The AECO gas price was the primary benchmark for Athabasca's natural gas sales in the Light Oil Division in 2014 and the first nine months of 2015 as Athabasca primarily delivered its sales product on the Alliance pipeline. In the fourth quarter of 2015, Athabasca began delivering sales product on the Fort Chicago pipeline and the NYMEX gas price became the primary benchmark for natural gas sales in the Light Oil Division. For the year ended December 31, 2015, the NYMEX price was US$2.67/MMBtu (2014 - US$4.39/MMBtu).

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

Light Oil Division

Operating Results

The following table summarizes the Light Oil operating results for the years ended December 31, 2015 and 2014:

Year ended ($ Thousands, except bbl, Mcf and boe amounts)	December 31, 2015	December 31, 2014
SALES VOLUMES		
Oil (bbl/d)	2,083	2,361
Natural gas (Mcf/d)	17,178	18,168
Natural gas liquids (bbl/d)	642	734
Total (boe/d)	5,587	6,120
Oil and Natural gas liquids %	49%	51%
LIGHT OIL OPERATING INCOME[1]		
Petroleum and natural gas sales	$ 62,547	$ 127,487
Midstream revenue	1,970	2,667
Royalties	(1,189)	(15,497)
Operating and transportation expenses	(29,400)	(35,923)
	$ 33,928	$ 78,734
REALIZED PRICES		
Oil ($/bbl)	$ 52.24	$ 89.20
Natural gas ($/Mcf)	2.66	4.89
Natural gas liquids ($/bbl)	26.08	67.90
Realized price ($/boe)	30.65	57.06
Royalties ($/boe)	(0.58)	(6.93)
Operating and transportation expenses[2] ($/boe)	(13.44)	(14.89)
LIGHT OIL OPERATING NETBACK[1] ($/boe)	$ 16.63	$ 35.24

(1) Refer to "Advisories and Other Guidance" beginning on page 27 for additional information on Non-GAAP Financial Measures.
(2) For the year ended December 31, 2015, operating and transportation expenses in the Light Oil Operating Netback figure includes midstream revenues of $0.97/boe (2014 - $1.19).

During the year ended December 31, 2015, Athabasca produced 5,587 boe/d (49% liquids), a 9% decrease compared to 6,120 boe/d (51% liquids) in 2014. Lower production was primarily due to natural well declines from the Company's Montney and Duvernay wells and unplanned pipeline restrictions on the TCPL and Alliance transportation systems during the year. The declines were partially offset by new wells brought on stream during 2015. Athabasca brought seven wells on stream in 2015 (six Duvernay, one Montney) including four wells brought on stream late in the fourth quarter of 2015.

Realized prices decreased by 46% during the year ended December 31, 2015 to $30.65/boe compared to 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 year ended December 31, 2015 were $1.2 million (2% percent of revenue) compared to $15.5 million (12% of revenue) during the prior year. Declines in royalty expenses were primarily due to lower royalty rates which declined due to lower market commodity prices as well as prior period adjustments to gas cost allowances recognized during the year.

Despite lower production volumes during the year ended December 31, 2015, compared to the same period in the prior year, operating and transportation expenses decreased from $14.89/boe to $13.44/boe, primarily due to cost savings initiatives undertaken in 2015.

Segment Income (Loss)

The following table summarizes the Light Oil Segment income (loss) for the year ended December 31, 2015 and 2014:

Year ended ($ Thousands)	December 31, 2015	December 31, 2014
Light Oil Operating Income[1]	$ 33,928	$ 78,734
Impairment loss	(456,732)	(102,244)
Depletion and depreciation	(60,645)	(73,848)
Loss on sale of assets	(1,486)	(92)
Exploration expense	(748)	—
LIGHT OIL SEGMENT INCOME (LOSS)	$ (485,683)	$ (97,450)

(1) Refer to "Advisories and Other Guidance" beginning on page 27 for additional information on Non-GAAP Financial Measures.

Impairment loss

In the fourth quarter of 2015, given continued deterioration in commodity prices and the value of the Light Oil assets implied by the Murphy Transaction, it was determined that indicators of impairment were present and Athabasca tested its Light Oil Development cash generating unit ("CGU") for impairment. The Murphy Transaction implied a recoverable fair value for the Light Oil Development CGU of $770.0 million which was below the CGU's carrying value of $1.23 billion and Athabasca recognized an impairment loss of $456.7 million for the year ended December 31, 2015.

In the fourth quarter of 2014, in Athabasca's Light Oil Exploration areas, the Company recognized a full impairment loss of $74.4 million. Athabasca also recognized $27.8 million of land expires in the Light Oil Exploration areas, bringing the total Light Oil expiration and impairment charges for the year ended December 31, 2014 to $102.2 million.

Depletion and depreciation

Year ended ($ Thousands)	December 31, 2015	December 31, 2014
Depletion of oil and gas assets	$ 57,490	$ 69,438
Depreciation of infrastructure assets	3,155	4,410
TOTAL LIGHT OIL DEPLETION AND DEPRECIATION	$ 60,645	$ 73,848

Depletion of oil and gas assets declined by $12.0 million during the year ended December 31, 2015 compared to the prior year, primarily due to lower depletion rates resulting from reserve additions in the Light Oil Division and lower production volumes. 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.

Loss on Sales of Assets

For the year ended December 31, 2015 and 2014, losses from assets sales primarily relate to the disposal of non-core acreage and other tangible equipment.

Exploration Expense

During the year ended December 31, 2015, Athabasca incurred exploration expenses of $0.7 million, which primarily relates to mineral lease rentals in the Company's Light Oil exploration areas which were fully impaired in the fourth quarter of 2014. These exploration costs were capitalized to exploration and evaluation assets during the year ended December 31, 2014.

Thermal Oil Division

Operating results

The following table summarizes the Thermal Oil operating results for the years ended December 31, 2015 and 2014:

Year ended ($ Thousands, except bbl, mcf and boe amounts)	December 31, 2015	December 31, 2014
VOLUMES (including capitalized volumes)[1][2]		
Bitumen production (bbl/d)	1,973	—
Bitumen sales (bbl/d)	1,526	—
Dilbit Sales (bbl/d)	1,956	—
Bitumen sales consists of:		
Bitumen sales capitalized (bbl/d)	42	—
Bitumen sales recognized in income (bbl/d)	1,484	—
	1,526	—
THERMAL OIL OPERATING INCOME (LOSS)[1][3]		
Blended bitumen sales	$ 21,301	$ —
Cost of diluent	(10,408)	—
Total bitumen sales	10,893	—
Royalties	(123)	—
Operating expenses - non-energy	(25,221)	—
Operating expenses - energy	(7,884)	—
Transportation and marketing	(7,865)	—
	$ (30,200)	$ —
REALIZED PRICES		
Blended bitumen sales ($/bbl)	$ 30.78	$ —
Bitumen sales ($/bbl)	$ 20.12	$ —
Royalties ($/bbl)	(0.22)	—
Operating expenses - non-energy ($/bbl)	(46.57)	—
Operating expenses - energy ($/bbl)	(14.55)	—
Transportation and marketing ($/bbl)	(14.52)	—
THERMAL OIL OPERATING NETBACK ($/bbl)	$ (55.74)	$ —

(1) For the year ended December 31, 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 year averaged over 365 days.
(2) 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.
(3) Refer to "Advisories and Other Guidance" beginning on page 27 for additional information on Non-GAAP Financial Measures.

During the year ended December 31, 2015, Athabasca completed construction and commissioning of Project 1 and achieved first oil in July. By the end of the year, 21 of the 25 well pairs were converted to production. Initial operating results from Project 1 were capitalized until August 1, 2015 when the project had been deemed to be ready for use in the manner intended by management.

For the 12 months ended December 31, 2015, Athabasca averaged 1,973 bbl/d of bitumen production and achieved an exit production rate of 7,460 bbl/d (December average). Reservoir performance continues to align with subsurface modelling and supports steam chamber maturity to continue to reduce SOR and ramp-up production towards nameplate by the end of 2016.

The Thermal Oil Operating Netback for the year ended December 31, 2015 was $(55.74)/bbl. 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 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 consist of the electricity to power the facility and natural gas which is used to create steam for the SAGD recovery process. Non-Energy operating costs consist of all other operational expenditures relating to lifting costs. Management is focused on operational excellence and supports ongoing cost saving initiatives to continually reduce production costs as the facility ramps up to nameplate production.

Transportation and marketing expenditures consist of the costs incurred to deliver dilbit product from the plant facility to market. During 2015, Athabasca trucked production to various sales points until December when commissioning of the dilbit pipeline from Hangingstone to Cheecham was completed. During the commissioning of the pipeline, approximately 40,000 bbls of produced dilbit were used to fulfill the Company's line-fill requirement to Cheecham. During December, an additional 140,000 bbls were transported to storage at Cheecham. First sales from the dilbit pipeline were completed in January 2016. Beginning in December 2015, transportation costs will primarily include payments for dedicated capacity on the dilbit pipeline.

Segment Income (Loss)

The following table summarizes the Thermal Oil Segment income (loss) for the years ended December 31, 2015 and 2014:

Year ended ($ Thousands)	December 31, 2015	December 31, 2014
Thermal Oil Operating Income[1]	$ (30,200)	$ —
Impairment loss	(180,000)	(58,821)
Depletion and depreciation	(7,967)	—
Exploration expense	(980)	—
Loss on sale of assets	(164)	(38,659)
Other income	—	3,511
Equity loss on investment	—	(390)
THERMAL OIL SEGMENT INCOME (LOSS)	$ (219,311)	$ (94,359)

(1) Refer to "Advisories and Other Guidance" beginning on page 27 for additional information on Non-GAAP Financial Measures.

Impairment loss

In the fourth quarter of 2015, given continued deterioration in commodity prices and recent federal and provincial government initiatives surrounding climate change and pipeline development which could impact the long-term development of Thermal Oil projects, it was determined that indicators of impairment were present and Athabasca tested its Thermal Oil CGUs for impairment. For the year ended December 31, 2015, Athabasca recognized an impairment loss of $180.0 million in the Dover West CGU based on its estimated recoverable value of $294.6 million.

For the year ended December 31, 2014, the Company recognized a full impairment loss of $53.5 million in its Grosmont CGU. Athabasca also relinquished $5.3 million in non-commercial Grosmont leases during 2014 bringing the total Thermal Oil relinquishment and impairment charges to $58.8 million.

There were no impairments of the Hangingstone or Birch CGUs in 2014 or 2015.

Depletion and Depreciation

Year ended ($ Thousands)	December 31, 2015	December 31, 2014
Depletion of oil and gas assets	$ 3,525	$ —
Depreciation of infrastructure assets	4,442	—
TOTAL THERMAL OIL DEPLETION AND DEPRECIATION	$ 7,967	$ —

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

Exploration Expense

During the year ended December 31, 2015, Athabasca incurred exploration expenses of $1.0 million which primarily relate to land retention costs in the Company's Thermal Oil Grosmont area assets which were fully impaired in the fourth quarter of 2014. These exploration costs were capitalized to exploration and evaluation assets during the year ended December 31, 2014.

Gain (Loss) on Sale of Assets and Other Income

On August 29, 2014, Athabasca sold its 40% interest in the Dover joint venture for net proceeds of $1,183.9 million consisting of $601.3 million in cash and $583.9 million in three promissory notes (the "Promissory Notes"). Athabasca recognized a net loss of $38.7 million during the twelve months ended December 31, 2014, primarily related to transaction costs of $49.0 million in respect of the settlement of certain claims made by Phoenix relating to future abandonment costs associated with petroleum and natural gas wells located in the Dover and MacKay River areas. The net loss incurred was partially offset by the de-recognition of certain decommissioning obligation liabilities previously recognized by Athabasca and working capital and other adjustments associated with the closing of the sale of the Dover investment. For the year ended December 31, 2014, Athabasca also recognized $3.5 million in time-value of money accretion on the Dover Investment prior to the sale.

For the year ended December 31, 2015, Athabasca incurred a loss on the sale of assets of $0.2 million primarily relating to the sale of non-core excess infrastructure in the Hangingstone area, mostly offset by a gain recognized on the final working capital adjustments associated with the closing of the sale of its 40% interest in the Dover joint venture.

Corporate Review

General and Administrative ("G&A")

Year ended ($ Thousands)	December 31, 2015	December 31, 2014
Salaries and benefits	$ 31,867	$ 65,720
Office costs	12,908	17,601
Legal, accounting and consulting	4,205	5,693
Stakeholder relations	1,174	1,753
Capitalized staff costs	(17,625)	(42,306)
TOTAL GENERAL AND ADMINISTRATIVE EXPENSES	$ 32,529	$ 48,461
Capitalization rate	35%	47%

During the year ended December 31, 2015, salaries and benefits declined by $33.9 million compared to the prior year. In 2014 and 2015, the Company undertook initiatives to streamline costs and better align the organization's cost structure to the current operating environment, its capital plans and growth objectives. As a result, Athabasca has reduced the size of its head office workforce by approximately 50% since the beginning of 2014. Athabasca also undertook a number of other cost efficiency initiatives in 2014 and 2015 that have resulted in lower office costs and legal, accounting and consulting related expenses.

Capitalized staff and environment costs decreased during the year ended December 31, 2015 compared to the same periods in the prior year, primarily due to staff reductions, the completion of Project 1 and a reduction in other Thermal Oil and Light Oil capital activities.

Restructuring and Other Charges

Year ended ($ Thousands)	December 31, 2015	December 31, 2014
Staff restructuring charges	$ 11,300	$ 10,468
Office lease provision	7,034	—
Cancellation charges	4,574	—
TOTAL RESTRUCTURING CHARGES AND OTHER CHARGES	$ 22,908	$ 10,468

For the years ended December 31, 2015 and 2014, Athabasca incurred staff restructuring charges of $11.3 million and $10.5 million, respectively, relating to the Company's cost reduction activities. The Company also recognized a loss of $7.0 million for the year ended December 31, 2015, relating to lease commitments on vacated office space primarily as a result of the staff reductions. For the year ended December 31, 2015, Athabasca also recognized net cancellation charges of $4.6 million primarily relating to Thermal Oil rig commitments.

Stock-based Compensation

During the year ended December 31, 2015, Athabasca incurred stock-based compensation expense of $9.5 million compared to $9.4 million during the same period in the prior year. Stock-based compensation expense remained consistent year over year as decreases in expense resulting from lower average balances of equity awards outstanding in 2015 and lower capitalization rates due to reduced Thermal Oil and Light Oil capital activity were mostly offset by higher forfeiture recoveries from 2014 restructuring activities.

Financing and Interest

Year ended ($ Thousands)	December 31, 2015	December 31, 2014
Interest and fees on indebtedness	$ 65,652	$ 60,005
Accretion of provisions	6,667	6,149
Amortization of debt issuance costs	7,404	11,441
Capitalized financing and interest	(39,686)	(49,188)
TOTAL FINANCING AND INTEREST	$ 40,037	$ 28,407

Interest and financing expenses are primarily attributable to the three debt instruments held by the Company. Interest expense and amortization of debt issuance costs are incurred on the Company's $550.0 million senior secured second lien notes ("Notes") which were issued during the fourth quarter of 2012. The Notes bear interest at a rate of 7.5% per annum. Interest and amortization of debt issuance costs are also incurred on the Company's US$225.0 million senior secured first lien term loan (the "Term Loan") issued in the second quarter of 2014. The Term Loan currently bears interest at a rate of approximately 8.25% per annum. Athabasca also incurs standby fees and fees on issued letters of credit on its $125.0 million credit facility ("Credit Facility") and its US$50.0 million delayed-draw Term Loan.

During the 12 months ended December 31, 2015, Athabasca incurred higher interest and fees on indebtedness of $5.6 million compared to the prior year. The increase was primarily due to Athabasca incurring a full year of interest expense on the Company's Term Loan in 2015, which was issued during the second quarter of 2014.

Compared to the prior year, capitalized financing and interest decreased by $9.5 million during the year ended December 31, 2015. The decrease was primarily due to the discontinuance of interest and financing cost capitalization in August of 2015 when Project 1 became ready for use, partially offset by a higher percentage of interest and financing costs being capitalized to Project 1 as the project neared completion during the first half of 2015.

Interest income and other

Year ended ($ Thousands)	December 31, 2015	December 31, 2014
Interest income on cash and cash equivalents	$ 7,243	$ 5,228
Interest income on Promissory Notes	4,864	3,235
Time value of money accretion	—	3,341
Other	409	125
TOTAL INTEREST INCOME AND OTHER	$ 12,516	$ 11,929

Interest income and other increased during the year ended December 31, 2015 by $0.6 million compared to the prior year. The increase was primarily due to higher interest income on cash, cash equivalents and short-term investments as average balances were higher in 2015 relative to the prior year. Athabasca also earned higher interest income on the Promissory Notes issued to Athabasca by Phoenix on the closing of the sale of the Dover Investment during the third quarter of 2014. The overall increase in interest income was partially offset by time value of money accretion on the Dover Investment earned in 2014 prior to its sale to Phoenix on August 29, 2014.

Foreign Exchange Loss, Net

Year ended ($ Thousands)	December 31, 2015	December 31, 2014
Unrealized foreign exchange loss	$ (49,121)	$ (15,353)
Realized foreign exchange loss	(114)	(351)
FOREIGN EXCHANGE LOSS, NET	$ (49,235)	$ (15,704)

Athabasca incurs foreign exchange gains and losses on the Company's US$225.0 million Term Loan, which was issued on May 7, 2014. Athabasca recognized a net foreign exchange loss in 2014 and 2015 primarily due to an unrealized loss on the loan principal as the value of the Canadian dollar declined relative to the US dollar in both years. During the year ended December 31, 2015, the average value of the Canadian dollar declined relative to the US dollar by 16% from 1.10:1 to 1.28:1. The foreign exchange rate as at December 31, 2015 was 1.38:1 (December 31, 2014 - 1.16:1).

Derivative Gain, Net

Year ended ($ Thousands)	December 31, 2015	December 31, 2014
Unrealized derivative gain	$ 49,946	$ 12,638
Realized derivative gain	3,945	56
DERIVATIVE GAIN, NET	$ 53,891	$ 12,694

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. Athabasca recognized a net derivative gain in 2014 and 2015 as the value of the Canadian dollar declined relative to the US dollar in both years.

Loss on Provisions

During the year ended December 31, 2015, Athabasca recognized a net loss on provisions of $8.4 million primarily relating to refined estimates of the timing and amount of expected cash inflows associated with the Company's office lease provision liability. Further softening of the downtown Calgary real estate market in 2015 from an increasing supply of available office space lowered Athabasca's estimate of future cash inflows that will be generated to offset its ongoing office lease obligations.

Deferred Income Tax Recovery

The deferred income tax recoveries of $108.4 million and $64.2 million during the years ended December 31, 2015 and 2014, respectively, were primarily due to non-capital losses incurred. The increase in deferred income tax recovery in 2015 was primarily due to higher impairment losses recognized during the year.

For the year ended December 31, 2015, Athabasca had an unrecognized deferred income tax asset of $93.8 million in respect of the value of tax pools exceeding the carrying value of the Company's net assets for accounting purposes. The Company has approximately $2.8 billion in tax pools, including $0.9 billion in non-capital losses available for immediate deduction against future income.

CAPITAL EXPENDITURES

The following table summarizes the consolidated capital expenditures made by the Company for the years ended December 31, 2015 and 2014:

Year ended ($ Thousands)	December 31, 2015	December 31, 2014
Light Oil Division	$ 175,977	$ 199,938
Thermal Oil Division	114,150	416,967
Corporate assets	1,540	9,953
Total expenditures on E&E and PP&E	291,667	626,858
Expenditures included in assets held for sale[1]	—	8,120
TOTAL CAPITAL EXPENDITURES[2]	$ 291,667	$ 634,978

(1) Relates to the Dover Investment that was sold to Phoenix on August 29, 2014.
(2) For the year ended December 31, 2015, capital expenditures include capitalized staff costs of $17.6 million (December 31, 2014 - $42.3 million) and capitalized interest and financing of $35.9 million (December 31, 2014 - $44.5 million). Excluded are non-cash capitalized costs consisting of capitalized stock-based compensation, decommissioning obligations assets and non-cash interest and financing.

For the year ended, December 31, 2015, Athabasca spent $291.7 million on capital expenditures, a 9% reduction compared to the capital budget guidance of $322 million provided by the Company on November 4, 2015. Capital expenditures were lower than budget guidance primarily due to cost savings associated with the 2015/16 Light Oil drilling program.

Light Oil Division

Year ended ($ Thousands)	December 31, 2015	December 31, 2014
Light Oil capital expenditures[1]		
Duvernay	$ 113,957	$ 148,379
Montney	33,393	29,321
Operations and other	15,462	16,105
Land and lease rentals	13,165	6,133
TOTAL LIGHT OIL CAPITAL EXPENDITURES	$ 175,977	$ 199,938

(1) For the year ended December 31, 2015, capital expenditures includes $7.2 million in capitalized staff costs (December 31, 2014 - $9.1 million).

For the year ended December 31, 2015, the Company spent $176.0 million primarily to drill 16 wells and complete nine wells as part of the 2014/15 and 2015/16 winter drilling programs.

In the Greater Kaybob area, Athabasca spent $114.0 million on the Duvernay Formation primarily to drill 12 wells (10 horizontal, two vertical). Athabasca also completed six Duvernay wells during the year, one of which had been drilled in the prior year.

In the Greater Placid area, Athabasca spent $33.4 million primarily on drilling and completion activities in the Montney Formation and infrastructure development. For the year ended December 31, 2015, Athabasca drilled four horizontal Montney wells and completed two Montney wells, including one well that had been drilled in the prior year. Starting in the fourth quarter of 2015, Athabasca commenced construction of a pipeline that will connect the Company's Montney wells in the Greater Placid area to its regional infrastructure at Saxon. Athabasca anticipates that the pipeline will be completed in early 2016.

Athabasca brought seven wells on stream during 2015 (six Duvernay, one Montney) including four wells late in the fourth quarter of 2015. The balance of remaining wells are anticipated to be brought on stream in 2016.

The Company spent $15.5 million primarily on optimization, maintenance and project support for the Light Oil Division's major infrastructure and ongoing operations. Athabasca also spent $13.2 million primarily to acquire additional acreage and retain lands in its core development areas.

Thermal Oil Division

Year ended ($ Thousands)	December 31, 2015	December 31, 2014
Hangingstone capital expenditures		
Central processing facility	$ 28,237	$ 144,561
Drilling, pads and pipelines	1,493	70,566
Base infrastructure	359	14,872
Total Project 1 base facility	30,089	229,999
Regional infrastructure and production assurance	946	62,152
Project support costs[(1)]	9,236	36,854
Capitalized start-up costs	24,978	—
Capitalized interest and financing[(2)]	35,988	44,513
Mineral properties – acquisitions and rentals	—	221
Total Project 1	101,237	373,739
Hangingstone expansion	3,738	26,886
Other Thermal Oil exploration	9,175	16,342
TOTAL THERMAL OIL CAPITAL EXPENDITURES	$ 114,150	$ 416,967

(1) Includes geosciences, regulatory and stakeholder costs and delineation/observation drilling. For the year ended December 31, 2015, project support costs include $10.4 million in capitalized staff costs (December 31, 2014 - $26.5 million).

(2) Excludes non-cash capitalized interest and financing.

Project 1

During the year ended December 31, 2015, Athabasca spent $101.2 million on Project 1 primarily to complete the project and commence operations. The Company completed Project 1 construction during the first quarter of 2015 and transitioned to operations during the second quarter. The project became ready for use during the third quarter of 2015 at which time the Company discontinued the capitalization of initial net operating costs as well as the capitalization of interest and financing costs associated with the project.

Third party construction of transportation facilities was also completed in the fourth quarter of 2015 and the diluent and dilbit pipelines were both fully operational by the end of 2015. The Company plans to continue to ramp-up operations throughout 2016 toward its targeted production potential of 12,000 bbl/d.

Hangingstone Expansion

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

Other Thermal Oil Exploration

For the year ended December 31, 2015, Athabasca spent $9.2 million on other Thermal Oil exploration areas primarily relating to ongoing infrastructure operations as well as land retention costs.

OUTLOOK

Preserving a strong balance sheet and continued financial discipline remain top priorities for Athabasca in 2016. The Company will limit capital expenditures with plans for continuing cost optimization. Athabasca is well positioned to advance its strategic operating priorities in a lower for longer pricing environment.

In December 2015, Athabasca released its 2016 capital budget of $91 million (gross) and average corporate production of 16,000 - 18,000 boe/d (gross). The following table reflects the Company's initial 2016 budget adjusted for the Murphy Transaction consisting of anticipated changes to the joint working interests and an estimated closing date in the second quarter of 2016. The figures also exclude purchase price adjustments from the January 1, 2016 effective date:

2016 Outlook	Original 2016 budget & guidance	Revised 2016 Outlook
CAPITAL ($ MILLIONS)		
Light Oil Division	$ 71	$ 40 - 45
Thermal Oil Division	11	11
Capitalized general and administrative	8	8
	$ 91	$ 60 - 65
PRODUCTION		
Light Oil production (boe/d)	7,000 - 8,000	4,000 - 4,500
Thermal Oil production (bbl/d)	9,000 - 10,000	9,000 - 10,000
	16,000 - 18,000	13,000 - 14,500

Following the closing of the Murphy Transaction, Athabasca expects to have approximately $900 million in cash, cash equivalents, short-term investments and the final Promissory Note. The Company's liquidity will be further bolstered by the $225 million capital carry commitment in the Duvernay. Athabasca intends to provided an updated 2016 capital budget on following closing of the Murphy Transaction.

The Company is continuing to evaluate alternatives to enhance its capital structure and remains committed to reducing total leverage by $300 million to $400 million during 2016. Core refinancing objectives of the Company include the extension of its 2017 debt maturities, a reduction in corporate carrying costs to increase sustainability and the preservation of a multi-year funding outlook that will allow the Company to continue to strategically advance its assets. Athabasca continues to believe that its demonstrated strong operational performance within both of its Light Oil and Thermal Oil areas are key drivers in the success of its refinancing initiatives.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity risk

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

Funding

As at December 31, 2015, Athabasca had cash and cash equivalents of $559.5 million and a Promissory Note of $133.9 million due in the third quarter of 2016. Following the closing of the Murphy Transaction, Athabasca is anticipated to have approximately $900 million of liquidity (cash, cash equivalents and the last promissory note from Brion Energy). The Company intends to proactively enhance its capital structure by retiring a portion of long-term debt in 2016. Balance sheet strength and flexibility will remain a key priority for Athabasca, particularly in the current operating environment.

It is anticipated that Athabasca's 2016 capital and operating budgets, including continued appraisal and development activities in the Light Oil Division and the continued ramp-up of Project 1, and any debt repayments will be funded with existing cash and cash equivalents, short-term investments, the Promissory Note, operating income from the Thermal Oil and Light Oil divisions, proceeds from the sales of assets, the Duvernay capital carry from the pending Murphy Transaction (Note 24) and available credit. Beyond 2016, the Company may require additional capital to develop its assets and Athabasca believes it will fund its capital programs through some combination of cash and cash equivalents, short-term investments, the Duvernay capital carry from the pending Murphy Transaction (Note 24), a reasonable level of debt and other external financing. The Company cannot guarantee the availability of these sources of additional funding and the availability of future funding will depend on, among other things, the current commodity price environment, performance in both the Light Oil Division and at Hangingstone, the Company's credit rating at the time and the current

state of the equity and debt capital markets. The Company has significant flexibility to adjust its capital programs in response to commodity price cycles or other constraints.

Indebtedness

The following table summarizes Athabasca's Net Debt for the year ended December 31, 2015 and 2014:

($ Thousands)	December 31, 2015	December 31, 2014
Long-term debt	$ 838,205	$ 786,649
Current liabilities	57,775	171,097
Current assets	(746,651)	(1,082,301)
Current portion of derivative asset (included in current assets)	5,382	930
NET DEBT[1]	$ 154,711	$ (123,625)

(1) Refer to "Advisories and Other Guidance" beginning on page 27 for additional information on Non-GAAP Financial Measures.

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.

On May 7, 2014, Athabasca entered into a credit agreement providing for a US$225 million term loan (the "Term Loan"), which was fully funded at closing, plus an additional US$50 million committed delayed draw term loan, which the Company may draw at its option at any time up until May 7, 2016, subject to compliance with certain conditions precedent and covenants (collectively the "Term Loans"). As of December 31, 2015, the delayed draw term loan was undrawn. As at December 31, 2015, Athabasca was in compliance with all of the Term Loan covenants.

On May 7, 2014, concurrent with entering into the Term Loans, the Company entered into a $125 million amended and restated credit agreement with a syndicate of financial institutions to replace its previous $350 million credit facility. The amended and restated credit facility (the "Credit Facility") is available on a revolving basis until April 30, 2017. The Company amended its tangible net worth covenant from a minimum of $2,750 million to $1,700 million. As at December 31, 2015, the Company's shareholders' equity was $2,482 million (December 31, 2014 - $3,164 million). As at December 31, 2015, Athabasca was in compliance with all of the Credit Facility covenants.

As of December 31, 2015, $7.3 million of letters of credit had been issued under the Credit Facility, with the balance of the facility undrawn. In the first quarter of 2016, Athabasca issued an additional letter of credit for $89.9 million in respect of financial assurance provisions associated with the Company's pipeline transportation commitments, reducing the remaining capacity of the credit facility to $27.8 million.

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

Refer to Athabasca's consolidated financial statements for the year ended December 31, 2015 for additional information regarding the Company's long-term debt and credit facilities.

Commitments and Contingencies

The following table summarizes Athabasca's estimated future minimum commitments as at December 31, 2015 for the following five years and thereafter:

($ Thousands)	2016	2017	2018	2019	2020	Thereafter	Total
Transportation	$ 52,252	$ 53,433	$ 48,527	$ 51,260	$ 51,260	$ 856,303	$ 1,113,035
Repayment of long-term debt[(1)(2)]	3,056	553,026	2,996	297,681	—	—	856,759
Interest expense on long-term debt[(2)]	66,813	61,471	24,987	8,726	—	—	161,997
Office leases	2,452	2,452	2,452	2,452	2,452	11,808	24,068
Purchase commitments and other[(3)]	11,415	—	—	—	—	—	11,415
Drilling rigs	2,764	2,915	—	—	—	—	5,679
TOTAL COMMITMENTS	$ 138,752	$ 673,297	$ 78,962	$ 360,119	$ 53,712	$ 868,111	$ 2,172,953

(1) The Term Loan is required to be repaid on May 19, 2017 if the Company has not redeemed or refinanced the Notes prior to this date.
(2) Estimated future interest and principal repayments relating to the Term Loan have been translated a rate of US$1.00 = C$1.3840 in the table above which is based on the current spot rate as at December 31, 2015.
(3) Purchase commitments and other primarily relates to Thermal Oil camp costs and long-lead equipment in the Light Oil Division.

Transportation commitments

Athabasca has entered into two transportation services agreements which support the Hangingstone projects. The first agreement was signed with Enbridge Pipelines (Athabasca) Inc. ("Enbridge") for the transportation of produced bitumen and blended diluents from Hangingstone. Included in the table above under Transportation are the minimum take or pay commitments for terminalling and transportation from Hangingstone to Cheecham and from Cheecham to Edmonton. The initial term of the agreement is 25 years with Athabasca having the option to extend over four renewal terms of five years each.

The second agreement was signed with Inter Pipeline Polaris Inc. ("IPPI") for the transportation of condensate to the Hangingstone project using the IPPI owned and operated Polaris Condensate Pipeline System. Included in the table above under Transportation are the minimum take or pay commitments under the agreement. The initial term of the agreement is 25 years with Athabasca having the option to extend over five renewal terms of five years each.

Athabasca is subject to certain financial assurance provisions under its pipeline transportation agreements which require the Company to provide financial collateral consisting of letters of credit. On January 4, 2016, Athabasca issued a letter of credit under the Company's Credit Facility for $89.9 million in respect of the financial assurance provisions associated with the Enbridge pipeline transportation services agreement, which became effective in conjunction with the pipeline becoming operational late in the fourth quarter of 2015. Athabasca currently has $97.2 million in aggregate letters of credit issued primarily relating to these transportation services obligations.

Other Commitments

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

Excluded from the table above is a commitment for $133.7 million in office leases which were assigned to a third party in December 2013.

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.

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

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.

Credit Risk

The maximum exposure to credit risk is represented by the carrying amounts of cash and cash equivalents, short-term investments, accounts receivable, income tax receivable, derivative assets and Promissory Notes on the consolidated balance sheets. Cash and cash equivalents 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 December 31, 2015 and December 31, 2014 Athabasca's cash, cash equivalents and short-term investments were held with four counterparties. The Company holds investments in term deposits with large reputable financial institutions. The Company's management believes that credit risk associated with these investments is low. At December 31, 2015, the largest institution held 32% of the balances (December 31, 2014 - 35%).

As at December 31, 2015, 40% of the accounts receivable balance relates to the sale of petroleum and natural gas and was substantially collected within 30 days after the end of the period (December 31, 2014 - 23%). Joint interest billings and equipment disposals with partners account for 18% of accounts receivable (December 31, 2014 - 47%). 30% of the accounts receivable balance relates to GST, a cash call receivable and other receivables (December 31, 2014 - 22%). Additionally, 12% relates to accrued interest on the Promissory Note (December 31, 2014 - 8%). Management believes collection risk on the outstanding accounts receivable as at December 31, 2015 is low given the high credit quality of the Company's material counterparties. No material amounts were past due at December 31, 2015.

As at December 31, 2015 Athabasca holds $136.9 million in a remaining Promissory Note including the note principal and accrued interest. The Promissory Note is unconditional and secured by an irrevocable, standby letter of credit issued by HSBC Bank Canada ("HSBC"). Management believes that credit risk associated with this receivable is low as Phoenix is a wholly owned subsidiary of PetroChina, an investment grade rated corporation, and HSBC is a large reputable financial institution. The first and second Promissory Notes, which matured on March 2, 2015 and August 28, 2015 respectively, were fully collected on maturity.

Foreign exchange risk

The Company is exposed to foreign exchange risk on its US dollar denominated Term Loan and US dollar forward contract as described below. If the Canadian dollar strengthened by 5% relative to the US dollar, holding all other variables constant, the derivative asset of $62.6 million would decrease by $16.7 million. Long-term debt would decrease by $15.3 million resulting in a net $1.4 million loss. A 5% decrease in the Canadian dollar relative to the US dollar, holding all other variables constant, would increase the derivative asset by $16.7 million and increase long-term debt by $15.3 million resulting in a net $1.4 million gain.

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

($ Thousands)	December 31, 2015	December 31, 2014
OPENING DERIVATIVE ASSET	$ 12,638	$ —
Unrealized derivative gain	49,946	12,638
CLOSING DERIVATIVE ASSET	$ 62,584	$ 12,638
Presented as:		
Current portion of derivative asset	$ 5,382	$ 930
Long-term portion of derivative asset	$ 57,202	$ 11,708

Interest Rate Risk

The Company's exposure to interest rate fluctuations on interest earned on the floating rate cash balance of $480.6 million, from a 1.00% change in interest rates, would be approximately $4.8 million for a 12 month period (year ended December 31, 2014 - $4.4 million). The Company is also exposed to interest rate cash flow risk on its floating rate Term Loan. However, given that the Company has a 1.00% LIBOR floor on its Term Loan, a decrease in the rate would have no impact. A 1.00% increase in LIBOR above the existing rate would result in a US$1.4 million ($1.9 million) increase in interest expense for a 12 month period (year ended December 31, 2014 - US$0.6 million ($0.7 million)).

Off Balance Sheet Arrangements

The Company has a number of transportation, office lease agreements, 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 year ended December 31, 2015, the Company issued 2.2 million common shares. Issuances of Athabasca’s common shares in 2015 relate to the Company’s equity-settled share-based compensation plans.

Outstanding Share Data

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

As at March 5, 2016	
Common shares issued and outstanding	404,590,239
Convertible securities:	
Stock options	9,218,141
Restricted share units (2010 RSU Plan)	5,615,013
Restricted share units (2015 RSU Plan)	2,272,850
Performance share units	1,260,500
Deferred share units	663,082

During the year ended December 31, 2015, the Company established two new stock-based compensation award plans. The Company created a deferred share unit plan for non-management directors of the Company (the "DSU Plan"). Athabasca also created a new restricted share unit plan (the "2015 RSU Plan") which replaced the Company's previous restricted share unit plan (the "2010 RSU Plan"). All RSUs granted after April 1, 2015 are issued under the 2015 RSU Plan. Previously awarded grants under the 2010 RSU Plan remain issued and outstanding in accordance with that plan's terms.

For additional information regarding these compensation plans, refer to the Company's 2015 Information Circular filed on SEDAR dated March 17, 2015 and the consolidated financial statements of the Company for the year ended December 31, 2015.

SUMMARY OF QUARTERLY RESULTS

Light Oil Operating results

The following table summarizes the Light Oil operating results for the three months ended December 31, 2015 and 2014:

Three months ended ($ Thousands, except bbl, Mcf and boe amounts)	December 31, 2015	December 31, 2014
SALES VOLUMES		
Oil (bbl/d)	2,347	2,458
Natural gas (Mcf/d)	17,664	17,428
Natural gas liquids (bbl/d)	583	672
Total (boe/d)	5,873	6,035
Oil and Natural gas liquids %	50%	52%
LIGHT OIL OPERATING INCOME[1]		
Petroleum and natural gas sales	$ 15,085	$ 24,804
Midstream revenue	1,099	509
Royalties	1,440	(3,556)
Operating and transportation expenses	(7,073)	(9,326)
	$ 10,551	$ 12,431
REALIZED PRICES		
Oil ($/bbl)	$ 46.23	$ 72.17
Natural gas ($/Mcf)	2.24	3.81
Natural gas liquids ($/bbl)	27.12	38.32
Realized price ($/boe)	27.89	44.66
Royalties ($/boe)	2.67	(6.40)
Operating and transportation expenses[2] ($/boe)	(11.06)	(15.88)
LIGHT OIL OPERATING NETBACK[1] ($/boe)	$ 19.50	$ 22.38

(1) Refer to "Advisories and Other Guidance" beginning on page 27 for additional information on Non-GAAP Financial Measures.
(2) For the three months ended December 31, 2015, operating and transportation in the Light Oil Operating Netback includes midstream revenues of $1.90/boe (2014 - $0.91).

Light Oil production was lower during the fourth quarter of 2015, compared to the fourth quarter of 2014, primarily due to natural well declines on existing wells, partially offset by four new wells being brought on stream late in the quarter. Realized oil and gas prices declined by 38% during the fourth quarter of 2015, compared to the same period in the prior year, primarily due to lower global commodity prices oil and natural gas.

Royalties declined during the fourth quarter of 2015, compared to the fourth quarter of 2014, primarily due to lower royalty rates which decline on lower oil and gas prices. Athabasca also recognized a royalty expense recovery during the fourth quarter of 2015 due to prior period adjustments to gas cost allowances. Operating expenses and transportation expenses per boe declined primarily due to ongoing cost savings initiatives undertaken in 2015 and higher midstream revenues.

The following table summarizes the Light Oil Segment income (loss) for the three months ended December 31, 2015 and 2014:

Three months ended ($ Thousands)	December 31, 2015	December 31, 2014
Light Oil Operating Income[1]	$ 10,551	$ 12,431
Impairment loss	(456,732)	(94,129)
Depletion and depreciation	(12,328)	(16,625)
Loss on sale of assets	(2,319)	(274)
LIGHT OIL SEGMENT INCOME (LOSS)	$ (460,828)	$ (98,597)

(1) Refer to "Advisories and Other Guidance" beginning on page 27 for additional information on Non-GAAP Financial Measures.

Athabasca recognized an impairment loss of $94.1 million in the fourth quarter of 2014 relating to the Company's Light Oil Exploration areas. In the fourth quarter of 2015, Athabasca recognized an impairment loss of $456.7 million in the Company's Light Oil Development area. Depletion and depreciation declined during the fourth quarter of 2015, compared to the same period in the prior year, primarily due to lower depletion rates from higher reserves and lower production during the quarter. Losses from asset sales for the three months ended December 31, 2015 and 2014, primarily relate to the disposal of non-core acreage and excess capital inventory.

Thermal Oil Operating results

The following table summarizes the Thermal Oil operating results for the three months ended December 31, 2015 and 2014:

Three months ended ($ Thousands, except bbl, mcf and boe amounts)	December 31, 2015	December 31, 2014
VOLUMES		
Bitumen production (bbl/d)	5,708	—
Bitumen sales (bbl/d)	4,096	—
Dilbit Sales (bbl/d)	5,243	—
THERMAL OIL OPERATING INCOME (LOSS)[(1)(3)]		
Blended bitumen sales	$ 15,138	$ —
Cost of diluent	(7,137)	—
Total bitumen sales	8,001	—
Royalties	(105)	—
Operating expenses - non-energy	(15,853)	—
Operating expenses - energy	(4,547)	—
Transportation and marketing	(5,662)	—
	$ (18,166)	$ —
REALIZED PRICES		
Blended bitumen sales ($/bbl)	$ 31.38	$ —
Total bitumen sales ($/bbl)	$ 21.23	$ —
Royalties ($/bbl)	(0.28)	—
Operating expenses - non-energy ($/bbl)	(42.07)	—
Operating expenses - energy ($/bbl)	(12.07)	—
Transportation and marketing ($/bbl)	(15.03)	—
THERMAL OIL OPERATING NETBACK[(1)] ($/bbl)	$ (48.22)	$ —

(1) Refer to "Advisories and Other Guidance" beginning on page 27 for additional information on Non-GAAP Financial Measures.

Thermal Oil operating losses relates to initial operating results from Project 1, the Company's first Thermal Oil project which commenced operations during the first quarter of 2015 and achieved first oil in July. The Company continues to ramp-up the project which is anticipated to reach targeted production capacity of 12,000 bbl/d by the end of 2016.

The Thermal Oil Operating Netback for the quarter ended December 31, 2015 was $(48.22)/bbl. Negative Operating Netbacks are customary during ramp-up of a SAGD project as revenues from lower initial production is more than offset by operating and transportation costs which are largely fixed in nature regardless of production volumes. Athabasca anticipates that operating costs per barrel from Project 1 will materially improve as production increases.

The following table summarizes the Thermal Oil Segment income (loss) for the three months ended December 31, 2015 and 2014:

Three months ended ($ Thousands)	December 31, 2015	December 31, 2014
Thermal Oil Operating Income[(1)]	$ (18,166)	$ —
Impairment loss	(180,000)	(53,557)
Depletion and depreciation	(5,443)	—
Exploration expense	(368)	—
Loss on sale of assets	(164)	—
THERMAL OIL SEGMENT INCOME (LOSS)	$ (204,141)	$ (53,557)

(1) Refer to "Advisories and Other Guidance" beginning on page 27 for additional information on Non-GAAP Financial Measures.

Athabasca recognized an impairment loss of $53.6 million in the fourth quarter of 2014 relating to the Company's Grosmont CGU. In the fourth quarter of 2015, Athabasca recognized an impairment loss of $180.0 million relating to the Company's Dover West CGU. For the three months ended December 31, 2015, depletion and depreciation relates to initial operations of Project 1, which commenced production during the third quarter of 2015.

Results of Operations

The following table summarizes Athabasca's consolidated results of operations for the quarters ended December 31, 2015 and 2014:

Three months ended December 31, ($ Thousands)	Consolidated 2015	2014
LIGHT OIL SEGMENT INCOME	$ (460,824)	$ (98,597)
THERMAL OIL SEGMENT INCOME	(204,141)	(53,557)
CORPORATE		
Interest income and other	2,274	4,817
Financing and interest	(20,661)	(4,138)
General and administrative	(7,158)	(12,496)
Restructuring and other charges	(4,264)	(4,715)
Stock-based compensation	(851)	(2,619)
Depreciation	(729)	(1,481)
Foreign exchange gain (loss), net	(9,892)	(8,471)
Derivative gain (loss), net	9,747	9,546
Loss on Provision	(2,387)	—
Deferred income tax recovery	94,511	42,204
NET LOSS AND COMPREHENSIVE LOSS	$ (604,375)	$ (129,507)

Interest income and other decreased in the fourth quarter of 2015, compared to the same quarter in the prior year, primarily due to lower interest rates and lower average balances of cash, cash equivalents, short-term investments and Promissory Notes held in the period. Financing and interest expense was higher in the fourth quarter of 2015 primarily due to the discontinuance of capitalization of interest and financing expenses to Project 1 during the third quarter of 2015 when the asset became ready for use.

General and administrative costs decreased in the fourth quarter of 2015, compared to the same quarter in the prior year, primarily due to staff reductions that occurred in the first and fourth quarters of 2015 and other cost savings initiatives. Stock-based compensation expense declined during the fourth quarter of 2015, compared to the fourth quarter of 2014, primarily due to higher forfeitures from staff restructuring and lower fair values per award on new equity awards granted in 2015.

The net foreign exchange losses incurred in the fourth quarters of 2014 and 2015 relate primarily to an unrealized loss on the Company's US dollar denominated Term Loan as a result of a decrease in the value of the Canadian dollar. Concurrent with the Term Loan, Athabasca entered into a three-year foreign exchange par forward contract to reduce the Company's exposure to fluctuations in foreign exchange rates on its US dollar denominated long-term debt. The net derivative gains incurred during the fourth quarters of 2014 and 2015 primarily related to unrealized gains as a result of an decline in the value of the Canadian dollar in 2014 and 2015.

The Loss on Provision primarily relates to refined estimates of the timing and amount of expected cash inflows used to determine the Company's office lease provision liability. The deferred income tax recoveries in the fourth quarters of 2014 and 2015 relate primarily to net operating losses. The deferred income tax recovery was significantly higher during the fourth quarter of 2015, compared to the same period in the prior year, primarily due to the incurrence of higher impairment losses than in the prior year.

Capital expenditures

The following table summarizes the capital expenditures of the Company for the quarters ended December 31, 2015 and 2014:

Three months ended ($ Thousands)	December 31, 2015	December 31, 2014
Light Oil Division	$ 50,921	$ 87,870
Thermal Oil Division	2,257	78,876
Corporate assets	—	4,427
TOTAL CAPITAL EXPENDITURES[(1)]	$ 53,178	$ 171,173

(1) For the three months ended December 31, 2015, capital expenditures includes capitalized staff costs of $2.2 million (December 31, 2014 - $10.8 million) and capitalized interest and financing of $nil (December 31, 2014 - $13.9 million). Excluded are non-cash capitalized costs consisting of capitalized stock-based compensation, decommissioning obligations assets and non-cash interest and financing.

For the three months ended December 31, 2014 and 2015, capital expenditures in the Light Oil Division primarily relate to Athabasca's drilling programs in the Greater Kaybob and Greater Placid areas. Minimal capital expenditures were incurred in the Thermal Oil

Division during the three months ended December 31, 2015 with Project 1 completed in March 2015 and ready for use in the third quarter. Expenditures during the fourth quarter of 2014 primarily relates to final construction activities associated with Project 1.

Quarterly Results

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

	2015				2014			
($ Thousands, Except Share and Per Barrel Amounts)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	$ 42.18	$ 46.43	$ 57.94	$ 48.63	$ 93.00	$ 97.19	$ 102.96	$ 98.68
Western Canadian Select (C$/bbl)	$ 36.86	$ 43.29	$ 71.24	$ 60.35	$ 83.03	$ 105.84	$ 112.31	$ 108.89
Edmonton Par (C$/bbl)	$ 52.85	$ 56.17	$ 67.63	$ 51.79	$ 94.49	$ 97.03	$ 106.67	$ 99.74
Edmonton Condensate (C5+) (C$/bbl)	$ 54.52	$ 56.94	$ 69.81	$ 55.42	$ 100.42	$ 99.87	$ 112.49	$ 110.58
AECO (C$/GJ)	$ 2.33	$ 2.75	$ 2.53	$ 2.61	$ 4.25	$ 3.82	$ 4.71	$ 5.42
NYMEX Henry Hub (US$/MMBtu)	$ 2.27	$ 2.80	$ 2.64	$ 2.98	$ 4.39	$ 4.07	$ 4.59	$ 4.94
Foreign exchange (CAD : USD)	$ 1.34	$ 1.31	$ 1.23	$ 1.24	$ 1.16	$ 1.12	$ 1.09	$ 1.10
LIGHT OIL DIVISION								
Sales volumes (boe/d)	5,873	5,145	5,459	5,877	6,035	6,381	5,768	6,299
Realized price ($/boe)	$ 27.89	$ 31.34	$ 34.43	$ 29.35	$ 44.66	$ 56.90	$ 65.97	$ 61.12
Revenues[2]	$ 17,624	$ 14,043	$ 17,666	$ 13,981	$ 21,757	$ 29,892	$ 32,587	$ 30,421
Light Oil Operating Income[1]	$ 10,551	$ 6,096	$ 10,689	$ 6,578	$ 12,431	$ 21,154	$ 24,207	$ 20,943
Light Oil Operating Netback[1] ($/boe)	$ 19.50	$ 12.88	$ 21.51	$ 12.46	$ 22.38	$ 36.03	$ 46.12	$ 36.95
Capital expenditures	$ 50,921	$ 31,465	$ 14,959	$ 79,241	$ 87,870	$ 19,772	$ 14,847	$ 77,449
THERMAL OIL DIVISION								
Bitumen production (bbl/d)[3]	5,708	2,105	—	—	—	—	—	—
Sales volumes (bbl/d)	4,096	1,792	—	—	—	—	—	—
Realized price ($/bbl)	$ 21.23	$ 17.54	$ —	$ —	$ —	$ —	$ —	$ —
Revenues[2]	$ 15,033	$ 6,145	$ —	$ —	$ —	$ —	$ —	$ —
Thermal Oil Operating Income[1]	$ (18,166)	$ (12,146)	$ —	$ —	$ —	$ —	$ —	$ —
Thermal Oil Operating Netback[1]($/bbl)	$ (48.22)	$ (73.67)	$ —	$ —	$ —	$ —	$ —	$ —
Capital expenditures	$ 2,257	$ 9,366	$ 33,118	$ 68,504	$ 78,876	$ 89,455	$ 90,556	$ 157,958
OPERATING RESULTS								
Cash Flow from Operations	$ (54,496)	$ (17,933)	$ 8,576	$ (2,610)	$ (8,883)	$ 30,371	$ (18,641)	$ 15,412
Funds Flow from Operations[1]	$ (30,141)	$ (24,223)	$ 5,085	$ 3,162	$ (2,520)	$ 7,203	$ 5,016	$ 9,468
Net income (loss)	$ (604,375)	$ (38,241)	$ (29,044)	$ (25,112)	$ (129,507)	$ (19,939)	$ (56,766)	$ (21,346)
Net income (loss) per share - basic	$ (1.50)	$ (0.09)	$ (0.07)	$ (0.06)	$ (0.32)	$ (0.05)	$ (0.14)	$ (0.05)
Net income (loss) per share - diluted	$ (1.50)	$ (0.09)	$ (0.07)	$ (0.06)	$ (0.32)	$ (0.05)	$ (0.14)	$ (0.05)
BALANCE SHEET ITEMS								
Cash and cash equivalents ($)	559,487	671	582,396	570,290	531,475	722,747	182,499	129,385
Short-term investments ($)	—	—	—	92,873	47,618	—	—	20,350
Promissory Notes - short-term ($)	133,892	133,892	150,000	150,000	450,000	450,000	—	—
Promissory Notes - long-term ($)	—	—	133,892	133,892	133,892	133,892	—	—
Assets held for sale ($)	—	—	—	—	—	—	1,232,279	1,226,751
Total assets ($)	3,462,442	4,160,344	4,173,704	4,244,486	4,297,803	4,413,935	4,459,943	4,327,802
Net Debt ($)[1]	154,711	55,433	109,713	68,005	(123,625)	(305,161)	(555,789)	(700,788)
Long-term debt ($)	838,205	827,773	807,167	810,758	786,649	777,528	764,788	534,293
Shareholders' equity ($)	2,482,140	3,085,499	3,119,224	3,141,453	3,164,186	3,289,083	3,301,011	3,353,444

(1) Refer to "Advisories and Other Guidance" beginning on page 27 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 quarter ended September 30, 2015, production volumes on a bbl/d basis include capitalized volumes.

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 year ended December 31, 2015, there were no changes to the 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. Upon the commencement of Project 1 operations during the third quarter of 2015, Athabasca recognized inventory on the balance for the first time in the consolidated financial statements under the guidance of IAS 2 Inventories. Inventory consists of crude oil products and warehouse consumables. The carrying value of inventory includes all direct expenditures required to bring the inventory to its present location and condition, including transportation expenses. Athabasca values its inventory using the weighted average cost method and inventory is held at the lower of cost and net realizable value at each reporting period. If the carrying value exceeds the net realizable value, a write-down is recognized. A change in circumstance could result in a reversal of the write-down for inventory that remains on hand in a subsequent period.

Significant Accounting Estimates and Judgments

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

Prior to the closing of the sale of Dover on August 29, 2014, valuation of the Dover Put Option included estimates as to the expected timing and probability of regulatory approval as well as the probability of the Company exercising the option. Judgment was also applied in determining the appropriate discount rate to be used in the valuation and additional costs to be incurred prior to closing. At each reporting date the fair value of the Dover Put Option was assessed based on the most recent information with regards to the estimates discussed above. The accretion of the time value of money was recognized through interest income and any unrealized gains or losses were recognized through net income.

Included in the carrying value of property, plant and equipment are accumulated depletion, depreciation and impairment charges that are determined, in part, by utilizing estimates based on Athabasca's reserves, resources and land acreage values. The estimates of reserves and resources include estimates of the recoverable volumes of oil, gas and bitumen, future commodity prices and future costs required to develop and produce the assets. Reserve and resource estimates and future cash flows could be revised either upwards or downwards based on updated information from drilling and operating results as well as changes to future commodity price estimates and changes to the anticipated timing of project development. The rates used to discount future cash flows are based on judgment of economic and operating factors. Changes in these factors could increase or decrease the discount rate which may result in material changes to the estimated recoverable amount of the assets. Estimates also include the anticipated timing and cash flows associated with future capital carry receivable (Note 24). Exploration and evaluation assets require judgment as to whether future economic benefits exist, including the estimated recoverability of contingent resources, technology uncertainty and the ability to finance exploration and evaluation projects, where technical feasibility and commercial viability has not yet been determined.

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

The provision for the office lease is based upon numerous assumptions including inflation factors, credit-adjusted discount rates, actual settlement amounts and estimates of future recoveries. Actual costs and cash outflows could differ from the estimates as a result of changes in any of the above noted assumptions.

The provision for income taxes is based on judgments in applying income tax law and estimates on the timing and likelihood of reversal of temporary differences between the accounting and tax bases of assets and liabilities. The provision for income taxes is based on Athabasca's interpretation of the tax legislation and regulations which is also subject to change. Athabasca recognizes a tax provision when a payment to tax authorities is considered more likely than not. Income tax filings are subject to audits and re-assessments and changes in facts, circumstances and interpretations of the standards which may result in a material increase or decrease in the Company's provision for income taxes. As at December 31, 2015, Athabasca elected to not recognize deductible temporary differences in respect of income tax assets from non-capital losses .

The Company is using a derivative financial instrument to manage risks related to its US dollar denominated debt. The fair value of the derivative is determined using valuation models which require assumptions concerning the amount of timing of future cash flows, discount rates and foreign exchange rates. Athabasca's assumptions rely on external observable market data and data obtained from third parties. The resulting fair value estimates may not be indicative of the amount realized or settled in current market transactions and as such are subject to measurement uncertainty.

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

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

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

Principles of Consolidation

These consolidated financial statements reflect the activities of the Company and its wholly owned subsidiaries. Intercompany transactions and balances are eliminated upon consolidation. The Company accounted for its investment in the Dover joint arrangement as an equity investment up to the date of sale in accordance with IAS 28 Investments in Associates. Management had made an assessment under IFRS 10 Consolidated Financial Statements and IFRS 11 Joint Arrangements and determined that Athabasca did not control or jointly control its interests in the Dover joint arrangement as Athabasca did not have exposure to the majority of associated benefits or risks.

The Dover joint arrangement was an investment in which the Company had significant influence, as the Company held a 40% interest in the joint arrangement up until August 29, 2014 at which point the remaining interest was sold. The arrangement was accounted for as a long-term investment using the equity method of accounting whereby the carrying value of the investment was increased or decreased for the Company's percentage of net income or loss, reduced by dividends paid to the Company, and increased or decreased to reflect the Company's share of capital transactions.

Segment Reporting

The Company's operating segments are determined based on differences in the nature of their operations, products sold, economic characteristics, regulatory environments and management responsibility. Operating segments have been aggregated based on similar characteristics as follows:

- Light Oil - includes the Company's assets, liabilities and operating results for the exploration, development and production of unconventional oil, natural gas and natural gas liquids located in various regions in the province of Alberta.
- Thermal Oil - includes the Company's assets, liabilities and operating results for the exploration, development and production of bitumen from sand and carbonate rock formations located in the Athabasca region of Northern Alberta.

Segment results, assets and liabilities include items directly attributable to a segment and those items that can be allocated on a reasonable basis. Unallocated items are comprised mainly of corporate assets, head office expenses, interest income, finance and interest expense, and income tax assets and liabilities. There were no changes to the Company's operating segments during the year.

Exploration and Evaluation ("E&E") Assets

Costs of exploring for and evaluating oil and gas activities, including lease acquisition costs, exploratory drilling to delineate resource formations, geological and geophysical costs, engineering, licensing and regulatory fees, carrying charges on non-productive assets and employee salaries and stock-based compensation directly related to exploration and evaluation activities are initially capitalized. E&E costs do not include general prospecting or evaluation costs incurred prior to having obtained the legal rights to explore an area, these costs are expensed directly to the statement of income as they are incurred.

Tangible assets acquired and utilized to develop an E&E asset are recorded as part of the cost of the E&E asset. When a tangible asset is disposed of in the E&E phase the proceeds of the assets sold are de-recognized from the E&E asset pool with no gain or loss recognized.

E&E assets are carried at cost until both the technical feasibility and commercial viability of extracting a mineral resource is established. Technical feasibility and commercial viability of unconventional petroleum and natural gas activities is considered achieved when

proved reserves are determined to exist and the Company has received approval to proceed with commercial development by its Board of Directors. The technical feasibility and commercial viability of Thermal Oil activities is considered to be achieved when proved reserves are determined to exist and the Company has received approvals to proceed with commercial development by its Board of Directors and regulatory authorities. Upon technical feasibility and commercial viability being established, E&E assets are first tested for impairment and then reclassified from E&E assets to property, plant and equipment.

If the technical feasibility and commercial viability cannot be proved or if an impairment is recognized, subsequent expenditures are no longer capitalized and will be recognized as exploration expense.

Property, Plant and Equipment ("PP&E")

Items of PP&E are measured using historical cost less any accumulated impairment losses. The initial cost of an asset comprises its purchase price, any cost directly attributable to bringing the asset to the location and condition necessary for its intended use and an initial estimate of the cost of dismantling and removing the item and restoring the site on which it is located. Included in PP&E are assets that have been transferred from E&E upon the establishment of commercial viability and technical feasibility. Once Athabasca's projects are available for use in the manner intended by management, they will either be depleted or depreciated over their useful life depending on the nature of the asset.

Light Oil assets that are ready for use in the manner intended by management have been depleted using the unit-of-production method based on the ratio of production in the year to the related proved plus probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Depreciation of Light Oil Infrastructure assets is calculated using the straight-line method over the estimated useful life of the assets, which range from three to fifty years.

During the third quarter of 2015, Athabasca began recognizing depletion and depreciation of Hangingstone project ("Project 1"). The central processing facilities are depreciated on a unit-of-production basis over the total productive capacity of the facility. The supporting infrastructure is depreciated using 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.

Depreciation of corporate assets is calculated using the straight-line method over the estimated useful life of the asset, ranging from one to five years.

Impairment

E&E and PP&E assets are tested for impairment at the cash-generating unit ("CGU") level at each reporting date when facts and circumstances suggest that the carrying amount may exceed the recoverable amount. The recoverable amount is determined as the greater of the CGU's value in use ("VIU") and fair value less costs to sell ("FVLCTS"). CGUs are not larger than an operating segment. In assessing VIU, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. FVLCTS is defined as the amount obtainable from the sale of an asset or CGU in an arm's length transaction between knowledgeable parties, less the costs to dispose of the CGU.

The calculations identified above require the use of estimates and assumptions and are subject to changes as new information becomes available. Factors that are subject to change include estimates of future commodity prices, expected production volumes, land values, quantity of reserves and resources, discount rates, and future development and operating costs. Changes in assumptions used in determining the recoverable amount could have a material affect on the carrying value of the related E&E and PP&E assets and CGU's.

Financial Instruments

All financial instruments are initially recognized at fair value on the consolidated balance sheet. The Company has classified each financial instrument into the following categories: "held-for-trading"; "loans and receivables"; "held-to-maturity" and "other financial assets or liabilities." Subsequent measurement of the financial instruments is based on their classification. Unrealized gains and losses on held-for-trading financial instruments are recognized in the statement of loss. The other categories of financial instruments are recognized at amortized cost using the effective interest rate method.

The Company has classified its financial instruments as follows:

Financial Assets and Liabilities	Classification
Cash and cash equivalents	Held-for-trading
Short-term investments	Held-for-trading
Derivative asset	Held-for-trading
Accounts receivable	Loans and receivables
Income tax receivable	Loans and receivables
Promissory Notes	Held-to-maturity
Accounts payable and accrued liabilities	Other financial liabilities
Long-term debt	Other financial liabilities

Transaction costs for all financial assets and liabilities are expensed as incurred, with the exception of long-term debt. Transaction costs related to long-term debt are included in the initial fair value and the instruments are carried at amortized cost using the effective interest rate method. The fair value of Athabasca's long-term debt is derived from quoted prices provided by financial institutions or derived from quoted prices on debt instruments with similar credit risk and yield profiles.

Loans and receivables are financial assets with fixed or determinable payments that are not quoted in an active market. Athabasca's loans and receivables are comprised of accounts receivable and income tax receivable. These have been recognized at the amount expected to be received less any required discount to reduce their value to fair value.

Derivative financial instruments are used by the Company to manage risks related to its US dollar denominated debt. All derivatives have been classified at fair value though income or loss. Derivative financial instruments are included on the balance sheet and are classified as current or non-current based on the contractual terms specific to the instrument. Gains and losses on re-measurement of derivatives are shown separately on the income statement in the period in which they arise.

At each reporting date, the Company assesses whether there are any indicators that its financial assets are impaired. An impairment loss is only recognized if there is evidence of impairment and the loss event has an impact on future cash flow and can be reliably estimated.

ADVISORIES AND OTHER GUIDANCE

Non-GAAP Financial Measures

The "Light Oil Operating Netback", "Light Oil Operating Income", "Thermal Oil Operating Netback", "Thermal Oil Operating Income", "Funds Flow from Operations" and "Net Debt" financial measures contained in this MD&A do not have standardized meanings which are prescribed by IFRS and they are considered to be non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers and should not be considered in isolation with measures that are prepared in accordance with IFRS.

The Net Debt measure in this MD&A (including the comparatives thereto) is calculated by subtracting the current assets (excluding the current portion of derivative assets) from Company's current liabilities and long-term debt. The table on page 17 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 to in the consolidated financial statements for the years ended December 31, 2015 and 2014 to Funds Flow from Operations:

Year ended ($ Thousands)	December 31, 2015	December 31, 2014
Cash flow from operating activities	$ (67,826)	$ 18,177
Restructuring and other charges, excluding change in long-term portion of office lease provision	20,373	10,468
Changes in non-cash working capital	(3,031)	(6,619)
Reclamation expenditures	3,481	1,756
FUNDS FLOW FROM OPERATIONS	$ (47,003)	$ 23,782

The Funds Flow from Operations is not intended to represent cash flow from operating activities, net earnings or other measures of

financial performance calculated in accordance with IFRS. The Funds Flow from Operations measure allows management and others to evaluate the Company's ability to fund its capital programs and meet its ongoing financial obligations using cash flow internally generated from operating related activities.

On page 28 of the 2014 Management's Discussion and Analysis, restructuring charges and other was included in the Funds Flow From Operations non-GAAP financial measure. In 2015, the Company began excluding the restructuring charges and other from the non-GAAP financial measure in order to exclude anticipated non-recurring corporate costs of the Company. The 2014 comparative figures above and in the Summary of Quarterly Results have been adjusted to also exclude the restructuring charges and other in the Funds Flow from Operations non-GAAP financial measure. Funds Flow from Operations per share (basic and diluted) are calculated as Funds Flow from Operations divided by the number of weighted average basic and diluted shares outstanding.

The Light Oil Operating Income and Light Oil Operating Netback measures in this MD&A (including the comparatives thereto) are calculated by subtracting royalties and operating and transportation expenses from petroleum and natural gas sales and midstream revenues received. The Light Oil Operating Netback measure is presented on a per boe basis. The Light Oil Operating Income and the Operating Netback (per boe) measures allow management and others to evaluate the production results from the Company's Light Oil assets. The table on page 6 reconciles Light Oil Operating Income to *Note 9 - Segmented Information* in the consolidated financial statements for the year ended December 31, 2015.

The Thermal Oil Operating Income and Thermal Oil Operating Netback measures in this MD&A (including the comparatives thereto) are calculated by subtracting cost of diluent blending, royalties, operating expenses and transportation expenses from blended bitumen sales received. The Thermal Oil Operating Netback measure is presented on a per bbl basis. The Thermal Oil Operating Income and the Thermal Oil Operating Netback (per bbl) measures allow management and others to evaluate the production results from the Company's Thermal Oil assets. The table on page 8 reconciles Thermal Oil Operating Income to *Note 9 - Segmented Information* in the consolidated financial statements for the year ended December 31, 2015.

Disclosure Controls and Procedures

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

Part 1 of NI 51-109 defines DC&P as 'Controls and other procedures of an issuer that are designed to provide reasonable assurance that information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by an issuer in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the issuer's management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure'.

For the year ended December 31, 2015, an evaluation was carried out under the supervision of and with the participation of Athabasca's management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of the Company's DC&P. Based upon that evaluation, the Chief Executive Officer and the Chief Financial Officer of the Company concluded that the design and operation of the Company's DC&P were effective to ensure that the information required by Canadian securities regulatory authorities, will be recorded, processed, summarized and reported within the prescribed timelines.

Management's Report on Internal Control over Financial Reporting

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

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

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

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

Management, including the Chief Executive Officer and Chief Financial Officer, must assess the effectiveness of the Company's internal control over financial reporting as of December 31, 2015, based on *the Internal Control - Integrated Framework* (the "Framework") established by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In making its assessment, Management used the COSO 2013 Framework in order to evaluate the design and effectiveness of internal control over financial reporting. Based upon management's assessment of the effectiveness of the Company's internal control over financial reporting, the Company has maintained effective internal control over financial reporting as of December 31, 2015.

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 and bitumen blend;
- general economic, market and business conditions in Canada, the United States and globally;
- the substantial capital requirements of Athabasca's projects and the ability to obtain financing for Athabasca's capital requirements;
- failure to realize anticipated benefits of acquisitions or divestments;
- risks related to hydraulic fracturing;
- extent of, and cost of compliance with, government laws and regulations and the effect of changes in such laws and regulations from time to time;
- risks relating to changing royalty regimes;
- additional funding requirements and liquidity risk;
- variations in foreign exchange and interest rates;
- environmental risks and hazards and the cost of compliance with environmental regulations, including the licensee liability rating program, seismic activity regulations, GHG regulations and potential Canadian and U.S. climate change legislation;
- risks related to the finalization and closing of the Murphy Transaction;
- dependence upon Murphy as a working interest participant in its Light Oil assets and as operator of the Kaybob assets;
- risks related to the Amended Credit Facility, Term Loans and the Senior Secured Notes;
- Geopolitical risks;
- uncertainties inherent in estimating quantities of reserves and resources;
- risks and uncertainties inherent in Athabasca's operations, including those related to exploration, development and production of petroleum, natural gas and oil sands reserves and resources, including the production of oil sands reserves and resources using SAGD, TAGD or other in-situ recovery technologies;
- failure to meet development schedules and potential cost overruns;
- aboriginal claims;
- risks related to gathering and processing facilities and pipeline systems;
- availability of drilling and related equipment and limitations on access to Athabasca's assets;
- failure to accurately estimate abandonment and reclamation costs;
- the potential for management estimates and assumptions to be inaccurate;
- reliance on third party infrastructure;
- seasonality;
- hedging risks;
- risks associated with establishing and maintaining systems of internal controls;
- expiration of leases and permits or the failure of Athabasca or the holder of certain licenses, leases or permits to meet specific requirements of such licenses, leases or permits;
- breaches of confidentiality;
- inaccuracy of forward-looking information;
- expansion into new activities;
- risks related to the Common Shares.

For additional information regarding the risks and uncertainties to which the Company and its business are subject, please see the information under the headings "Forward Looking Information" below, and under the headings "Forward-Looking Statements" and

"Risk Factors" in the Company's most recent AIF, on the Company's SEDAR profile at www.sedar.com.

Forward Looking Information

This MD&A contains forward-looking information that involves various risks, uncertainties and other factors. All information other than statements of historical fact is forward-looking information. The use of any of the words "anticipate," "plan," "continue", "estimate", "expect", "may", "will", "project", "target", "should", "believe", "predict", "pursue" and "potential" and similar expressions are intended to identify forward-looking information. The forward-looking information is not historical fact, but rather is based on the Company's current plans, objectives, goals, strategies, estimates, assumptions and projections about the Company's industry, business and future financial results. This information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. No assurance can be given that these expectations will prove to be correct and such forward-looking information included in this MD&A should not be unduly relied upon. This information speaks only as of the date of this MD&A. In particular, this MD&A may contain forward-looking information pertaining to the following: the timing of the ramp-up of production and of achieving plateau production from Project 1; the Company's expectation that Netbacks will improve as production increases; the timing of drilling, completion and tie-in operations in the Company's Light Oil division; the benefits expected to be realized from placing the Company's Light Oil division Duvernay wells on a soak period; the Company's expected production from the Light Oil and Thermal Oil divisions during 2016; the expected timing of the Company's Light Oil division wells coming on-stream; the benefits expected to be realized from the use of recovery technologies in the Company's Light Oil division, including multi-stage, energized hybrid completion technology; the anticipation of lower service costs in the second half of 2016; the Company's expected flexibility in its pace of development; the Company's drilling plans, in particular, with respect to the Duvernay and Montney formations; the timing of the Company's well completion operations; expected timing for completion of the pipeline linking the Placid area to the existing Kaybob transporation infrastructure; the Company's plans for, and results of, exploration and development activities; the finalization and closing of the Murphy transaction; the Company's estimated future commitments; the receipt of proceeds from the remaining Promissory Note; the Company's expected funding-in-place at the end of 2016; the Company's business and financing plans; the Company's business and financing strategies; expectations regarding the 2016 capital budget; and the future allocation of capital.

With respect to forward-looking information contained in this MD&A, assumptions have been made regarding, among other things: the regulatory framework governing royalties, taxes and environmental matters in the jurisdiction in which the Company conducts and will conduct business; Athabasca's cash flow break-even commodity price; the Company's ability to obtain qualified staff and equipment in a timely and cost-efficient manner; the applicability of technologies for the recovery and production of the Company's reserves and resources; future capital expenditures to be made by the Company; future sources of funding for the Company's capital programs; the Company's future debt levels; future production levels; the Company's ability to obtain financing and/or enter into joint venture arrangements, on acceptable terms; operating costs; compliance of counterparties with the terms of contractual arrangements; impact of increasing competition; geological and engineering estimates in respect of the Company's reserves and resources; recoverability of reserves and resources and the geography of the areas in which the Company is conducting exploration and development activities and the quality of its assets.

Actual results could differ materially from those anticipated in this forward-looking information as a result of the risk factors set forth in the Company's most recent AIF dated March 10, 2016, available on SEDAR at www.sedar.com, including, but not limited to: Weakness in the oil and gas industry; fluctuations in market prices for crude oil, natural gas and bitumen blend; general economic, market and business conditions in Canada, the United States and globally; the substantial capital requirements of Athabasca's projects and the ability to obtain financing for Athabasca's capital requirements; global financial uncertainty; failure to realize anticipated benefits of acquisitions or divestments; risks related to hydraulic fracturing; factors affecting potential profitability; failure to obtain regulatory approvals or maintain compliance with regulatory requirements; extent of, and cost of compliance with, government laws and regulations and the effect of changes in such laws and regulations from time to time; risks relating to changing royalty regimes; additional funding requirements and liquidity risk; variations in foreign exchange and interest rates; environmental risks and hazards and the cost of compliance with environmental regulations, including the licensee liability rating program, seismic activity regulations, GHG regulations and potential Canadian and U.S. climate change legislation; risks related to the Murphy Transaction, including the risk that the parties are unable to meet the conditions precedent to closing the Murphy Transaction or that the Murphy Transaction does not close on the timeline anticipated or at all, dependence on Murphy as the operator of the Kaybob assets, dependence on Murphy as the Company's joint venture participant in the Company's Kaybob and Placid assets and dependence on Murphy's continued ability to pay the Kaybob carry commitment; risks related to the Amended Credit Facility, Term Loans and the Senior Secured Notes; Geopolitical risks; uncertainties inherent in estimating quantities of reserves and resources; Contractual counterparty risks and operational dependence; risks related to future acquisition and joint venture activities; risks and uncertainties inherent in Athabasca's operations, including those related to exploration, development and production of petroleum, natural gas and oil sands reserves and resources, including the production of oil sands reserves and resources using SAGD, TAGD or other in-situ recovery technologies; failure to meet development schedules and potential cost overruns; aboriginal claims; reliance on, competition for, loss of, and failure to attract key personnel; Financial assurance covenants and collateral requirements under the Company's pipeline transportation

agreements; risks related to gathering and processing facilities and pipeline systems; availability of drilling and related equipment and limitations on access to Athabasca's assets; increases in operating costs could make Athabasca's projects uneconomic; the effect of diluent and natural gas supply constraints and increases in the costs thereof; costs of new technologies; alternatives to and changing demand for petroleum products; gas over bitumen issues affecting operational results; risks related to Athabasca's filings with taxation authorities, including the risk of tax related reviews and reassessments; failure to accurately estimate abandonment and reclamation costs; the potential for management estimates and assumptions to be inaccurate; long term reliance on third parties; reliance on third party infrastructure; seasonality; hedging risks; risks associated with establishing and maintaining systems of internal controls; insurance risks; claims made in respect of Athabasca's operations, properties or assets; 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 1,000 Duvernay drilling locations referenced on page 1 of this MD&A includes: 15 proved undeveloped or non-producing locations, 27 probable undeveloped locations for a total of 42 undeveloped booked locations with the balance being unbooked locations. The 160 Montney drilling locations referenced on page 1 of this MD&A includes: 24 probable undeveloped locations, all of which have a proven component, with the balance being unbooked locations. Proved undeveloped locations and probable undeveloped locations are booked and derived from the Company's most recent independent reserves evaluation as prepared by GLJ as of December 31, 2015 and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal management estimates. Unbooked locations do not have attributed reserves or resources (including contingent or prospective). Unbooked locations have been identified by management as an estimation of Athabasca's multi-year drilling activities expected to occur over the next two decades based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, oil and natural

gas prices, provincial fiscal and royalty policies, costs, actual drilling results and additional reservoir information that is obtained and other factors.

Definitions

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

"**Contingent Resources**" are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include such factors as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "Contingent Resources" the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources may be divided into the following project maturity sub-classes: "Development Pending" is assigned to Contingent Resources for a particular project where resolution of the final conditions for development is being actively pursued (high chance of development), "Development On Hold" is assigned to Contingent Resources for a particular project where there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator. "Development Unclarified" is assigned to Contingent Resources for a particular project where evaluation is incomplete and there is ongoing activity to resolve any risks or uncertainties or which require significant further appraisal to clarify potential for development and where contingencies have yet to be defined, "Development Not Viable" is assigned to Contingent Resources for a particular project where no further data acquisition or evaluation is currently planned and there is a low chance of development.As at December 31, 2015, the Company is reporting Contingent Resources on a risked and unrisked basis located in its: Hangingstone asset area in the Development Pending project maturity sub-class and located in its Hangingstone, Dover West Sands and Birch asset areas for Development On Hold and Development Unclarified project maturity sub-classes.

"Proved Reserves" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated Proved Reserves.

"Probable Reserves" are those additional reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved Reserves plus Probable Reserves.

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

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

Abbreviations

AECO	Physical storage and trading hub for natural gas on the TransCanada Alberta transmission system which is the delivery point for various benchmark Alberta index prices.
AER	Alberta Energy Regulator
bbl	barrel
bbl/d	barrels per day
boe[(1)]	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
C$	Canadian Dollars
COGE	Canadian Oil and Gas Evaluation
CSS	Cyclic Steam stimulations
E&E	Exploration and evaluation assets
GAAP	Generally Accepted Accounting Principles
G&A	General and administrative
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMbbl	millions of barrels
MMboe	millions of barrels of oil equivalent
MMBtu	million British thermal units
NYMEX	New York Mercantile Exchange
PP&E	Property, plant and equipment
SAGD	steam assisted gravity drainage
SOR	Steam to oil ratio
TAGD	thermal assisted gravity drainage
TCPL	TransCanada Pipeline
US$	United states Dollars

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