Management's Discussion and Analysis

December 31, 2019

ATHABASCA OIL CORPORATION

This Management's Discussion and Analysis of the financial condition and results of operations ("MD&A") of Athabasca Oil Corporation ("Athabasca" or the "Company") is dated March 4, 2020 and should be read in conjunction with the audited consolidated financial statements of the Company for the years ended December 31, 2019 and 2018. 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 "Advisories and Other Guidance" section within this MD&A. Also see the "Advisories and Other Guidance" section within this MD&A for important information regarding the Company's reserves and resource information and abbreviations included in 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 4, 2020 ("AIF"). The Company's common shares are listed on the Toronto Stock Exchange under the trading symbol "ATH".

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ATHABASCA'S STRATEGY

Athabasca is a liquids-weighted intermediate producer with exposure to Canada's most active resource plays (Montney, Duvernay, Oil Sands). The Company offers investors excellent exposure to oil prices and is focused on maximizing profitability through prudent capital activity in its Light Oil and Thermal Oil operations. The Company's strategy is guided by:

- Light Oil - Montney at Placid ("Greater Placid") and Duvernay at Kaybob ("Greater Kaybob"): High Margin Liquids Rich Returns
- Thermal Oil: Low Decline Production
- Financial Sustainability: Flexible Capital, Strong Liquidity

Athabasca remains focused on its drive for free cash flow while maintaining its production base with prudent capital expenditures. Athabasca maintains long term optionality across a deep inventory of high-quality Thermal Oil projects and flexible Light Oil development opportunities. This balanced portfolio provides shareholders with differentiated exposure to liquids weighted production and significant long reserve life assets.

HIGHLIGHTS FOR THE QUARTER AND YEAR ENDED DECEMBER 31, 2019

Corporate

- Fourth quarter production of 36,403 boe/d (89% liquids) and 2019 production of 36,196 boe/d (87% liquids).
- Adjusted Funds Flow(1) of $21.5 million in the fourth quarter and $154.8 million for 2019.
- Consolidated Free Cash Flow(1) of $14.6 million for 2019.
- 2019 net income of $246.9 million.
- Strong balance sheet with funding capacity of $362.9 million including $254.4 million of cash and cash equivalents, $85.8 million of available credit facilities and a $22.7 million (undiscounted) capital-carry balance.

Light Oil Division

- Fourth quarter production of 8,642 boe/d (54% liquids) and 2019 production of 10,138 boe/d (54% liquids).
- Strong fourth quarter and 2019 Operating Netbacks(1) of $20.49/boe and $25.68/boe.
- Operating Income(1) of $16.3 million in the fourth quarter and $95.0 million for 2019.
- Capital Expenditures Net of Capital-Carry(1) of $50.8 million in 2019. Activity in Greater Kaybob included 18 (gross) wells drilled, 14 (gross) wells completed and 10 (gross) wells being placed on production. Activity in Greater Placid included 4 (gross) wells drilled and completion operations commencing on two multi-well pads (10 wells).

Thermal Oil Division

- Fourth quarter production of 27,761 bbl/d and 2019 production of 26,058 bbl/d.
- Operating Netbacks(1) of $12.44/bbl in the fourth quarter and $19.59/bbl for 2019.
- Operating Income(1) of $28.7 million in the fourth quarter and $182.2 million for 2019.
- 2019 capital expenditures of $89.3 million which included the completion and start-up of a sustaining Pad 7 at Leismer which has supported strong exit volumes of 20,100 bbl/d (December 2019).
- Secured 8,000 bbl/d of direct refinery sales in 2020 to mitigate apportionment risk on the Enbridge Mainline.

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

FINANCIAL & OPERATIONAL HIGHLIGHTS

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

($ Thousands, unless otherwise noted)	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
CONSOLIDATED				
Petroleum and natural gas production (boe/d)	36,403	37,984	36,196	39,203
Operating Income (Loss)[(1)(2)]	$ 42,881	$ (53,180)	$ 233,219	$ 94,118
Operating Netback[(1)(2)] ($/boe)	$ 13.84	$ (14.80)	$ 17.95	$ 6.52
Capital expenditures	$ 69,796	$ 65,399	$ 199,141	$ 276,328
Capital Expenditures Net of Capital-Carry[(1)]	$ 46,259	$ 46,042	$ 140,207	$ 193,980
LIGHT OIL DIVISION				
Petroleum and natural gas production (boe/d)	8,642	12,609	10,138	11,280
Percentage liquids (%)	54%	55%	54%	51%
Operating Income (Loss)[(1)]	$ 16,287	$ 22,121	$ 95,004	$ 107,144
Operating Netback[(1)] ($/boe)	$ 20.49	$ 19.07	$ 25.68	$ 26.02
Capital expenditures	$ 46,473	$ 39,569	$ 109,687	$ 192,495
Capital Expenditures Net of Capital-Carry[(1)]	$ 22,936	$ 20,212	$ 50,753	$ 110,147
THERMAL OIL DIVISION				
Bitumen production (bbl/d)	27,761	25,375	26,058	27,923
Operating Income (Loss)[(1)]	$ 28,658	$ (84,544)	$ 182,196	$ 10,669
Operating Netback[(1)] ($/bbl)	$ 12.44	$ (34.72)	$ 19.59	$ 1.03
Capital expenditures	$ 23,229	$ 25,703	$ 89,343	$ 83,696
CASH FLOW AND FUNDS FLOW				
Cash flow from operating activities	$ 32,975	$ (2,253)	$ 92,632	$ 83,844
per share - basic	$ 0.06	$ —	$ 0.18	$ 0.16
Adjusted Funds Flow[(1)]	$ 21,478	$ (75,296)	$ 154,760	$ 6,175
per share - basic	$ 0.04	$ (0.15)	$ 0.30	$ 0.01
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)				
Net income (loss) and comprehensive income (loss)	$ (8,757)	$ (488,479)	$ 246,865	$ (569,657)
per share - basic	$ (0.02)	$ (0.95)	$ 0.47	$ (1.11)
per share - diluted	$ (0.02)	$ (0.95)	$ 0.47	$ (1.11)
COMMON SHARES OUTSTANDING				
Weighted average shares outstanding - basic	523,428,276	515,862,850	521,316,320	514,151,731
Weighted average shares outstanding - diluted	523,428,276	515,862,850	526,290,689	514,151,731

As at ($ Thousands)	December 31, 2019	December 31, 2018
LIQUIDITY AND BALANCE SHEET		
Cash and cash equivalents	$ 254,389	$ 73,898
Available credit facilities[(3)]	$ 85,815	$ 126,491
Capital-carry receivable (current and long-term portion - undiscounted)	$ 22,740	$ 81,675
Face value of long-term debt[(4)]	$ 583,425	$ 614,070

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.
(2) Includes realized commodity risk management losses of $2.1 million and $44.0 million for the three months and year ended December 31, 2019, respectively (December 31, 2018 - $9.2 million gain and $(23.7) million loss).
(3) Includes available credit under Athabasca's Credit Facility and Unsecured Letter of Credit Facility (see page 15).
(4) The face value of the 2022 Notes is US$450 million. The 2022 Notes were translated into Canadian dollars at the December 31, 2019 exchange rate of US$1.00 = C$1.2965.

INDEPENDENT RESERVES AND RESOURCES EVALUATION

The Company's qualified independent reserve evaluators, McDaniel & Associates Consultants Ltd. ("McDaniel"), completed independent reserve and resource evaluations effective December 31, 2019 and 2018. Athabasca's light oil, natural gas and natural gas liquids reserves are located in the Greater Placid (Montney) and Greater Kaybob (Duvernay) areas within the Company's Light Oil Division. The Company's bitumen reserves are located in the Leismer, Corner and Hangingstone areas of the Company's Thermal Oil Division.

Refer to the "Advisories and Other Guidance" section within this MD&A and the Company's AIF dated March 4, 2020, for further details relating to Athabasca's reserves and contingent resources.

Reserves

At December 31, 2019, the Company had 1,297 MMboe of Proved plus Probable Reserves (December 31, 2018 - 1,279 MMboe). The following table shows the Company's reserves by division (tables may not add due to rounding):

	December 31, 2019			December 31, 2018		
Reserves	Proved Developed Producing	Proved	Proved plus Probable	Proved Developed Producing	Proved	Proved plus Probable
Light Oil Division[1]						
Greater Placid (MMboe)	7	33	49	9	36	50
Greater Kaybob (MMboe)	6	13	23	6	13	24
Total Light Oil Division (MMboe)	13	46	72	15	49	74
Thermal Oil Division[2]						
Leismer (MMbbl)	34	331	695	26	322	675
Corner (MMbbl)	—	—	353	—	—	353
Hangingstone (MMbbl)	35	80	177	37	82	177
Total Thermal Oil Division (MMbbl)	68	410	1,225	63	404	1,205
Consolidated reserves (MMboe)	81	456	1,297	78	453	1,279

(1) Light Oil reserves are comprised of tight oil, conventional natural gas, NGL's and shale gas.
(2) Thermal Oil reserves are comprised of bitumen.

In the Light Oil Division, reserves were relatively consistent year-over-year. Proved plus Probable liquids weighting increased to 53% driven by Duvernay development plans focused on the volatile oil window.

In the Thermal Oil Division, the Proved Developed Producing ("PDP") reserves increased by 8% to 68 MMbbl with support from Leismer Pad 7 wells being converted from Proved Undeveloped to PDP. Proved plus Probable reserves increased 2% from 1,205 MMbbl to 1,225 MMbbl for the year ended December 31, 2019 based on improved recovery factors.

Contingent Resources

As at December 31, 2019, Athabasca had 0.3 billion risked barrels (0.4 billion unrisked barrels) of Best Estimate Development Pending Contingent Resources in the Leismer area. In the Corner area, Athabasca had 0.4 billion risked barrels (0.5 billion unrisked barrels) of Best Estimate Development Pending Contingent Resources. In the Dover West Sands area, Athabasca had 1.3 billion risked barrels (2.2 billion unrisked barrels) of Best Estimate Development On Hold Contingent Resources.

BUSINESS ENVIRONMENT

Benchmark prices

(Average)	Three months ended December 31, 2019	2018	Change	Year ended December 31, 2019	2018	Change
Crude oil:						
West Texas Intermediate (WTI) (US$/bbl)[1]	$ 56.96	$ 58.81	(3) %	$ 57.03	$ 64.77	(12) %
West Texas Intermediate (WTI) (C$/bbl)[1]	$ 75.19	$ 77.70	(3) %	$ 75.70	$ 83.91	(10) %
Western Canadian Select (WCS) (C$/bbl)[2]	$ 54.27	$ 25.36	114 %	$ 58.75	$ 49.66	18 %
Edmonton Par (C$/bbl)[3]	$ 67.99	$ 42.75	59 %	$ 69.05	$ 69.36	- %
Edmonton Condensate (C5+) (C$/bbl)[4]	$ 69.22	$ 59.73	16 %	$ 69.58	$ 78.48	(11) %
WCS Differential:						
to WTI (US$/bbl)	$ (15.83)	$ (39.43)	(60) %	$ (12.76)	$ (26.31)	(52) %
to WTI (C$/bbl)	$ (20.92)	$ (52.34)	(60) %	$ (16.95)	$ (34.25)	(51) %
Edmonton Par Differential:						
to WTI (US$/bbl)	$ (5.37)	$ (26.30)	(80) %	$ (4.88)	$ (11.12)	(56) %
to WTI (C$/bbl)	$ (7.20)	$ (34.95)	(79) %	$ (6.65)	$ (14.55)	(54) %
Natural gas:						
AECO (C$/GJ)[5][6]	$ 2.35	$ 1.48	59 %	$ 1.67	$ 1.42	18 %
Chicago Citygate (US$/MMBtu)[6]	$ 2.20	$ 3.67	(40) %	$ 2.35	$ 3.02	(22) %
Foreign exchange:						
USD : CAD	1.3201	1.3213	- %	1.3273	1.2956	2 %

Primary benchmark for:
(1) Crude oil pricing in North America.
(2) Athabasca's blended bitumen sales.
(3) Crude oil sales in the Company's Light Oil Division.
(4) Condensate sales in the Company's Light Oil Division and for diluent purchases in the Thermal Oil Division.
(5) Natural gas consumed by Athabasca in order to generate steam in the Thermal Oil Division.
(6) Natural gas sales in the Company's Light Oil Division.

In 2019 and 2020 the Alberta government has continued mandated industry production curtailments at modest levels to manage unprecedented differentials due to a lack of egress. Athabasca is supportive of this government tool to manage extreme pricing dislocations and to provide a bridge to pipeline projects. WCS heavy differentials averaged US$12.76/bbl for 2019 and US$15.83/bbl for the fourth quarter of 2019. In the first quarter of 2020, differentials increased modestly to settle at US$20.53/bbl. The outlook for the balance of 2020 has improved to approximately US$15.75/bbl (March 2 strip) driven by seasonality impacts over the summer, pipeline optimization and industry crude by rail ramp-up.

The global heavy oil market continues to see structural supply declines in Venezuela and Mexico, extended OPEC production cuts and growing petrochemical demand. These shifting dynamics are expected to support heavy oil pricing benchmarks with US refineries in PADD II and III requiring a heavier feedstock. Athabasca is well positioned for this changing dynamic with its Thermal Oil assets.

With continued market access constraints, Athabasca has been prudent in securing long term transportation agreements and protecting realized pricing through its hedging program. For the balance of 2020 Athabasca has hedged approximately 12,500 bbl/d of WTI at US$55/bbl and approximately 14,500 bbl/d of WCS differential at US$18.25/bbl (March – December). 8,000 bbl/d is protected from apportionment through direct sales to refineries. The Company has secured long term capacity on the TC Energy Keystone XL pipeline and the Trans Mountain Expansion Project.

OUTLOOK

Athabasca is reiterating its front-end weighted 2020 capital program with expenditures aimed at sustaining base production. The 2020 capital expenditures are projected to be $125 million focused on resiliency by executing a program aimed at sustaining 2020 average production between 36,000 – 37,500 bbl/d (88% liquids).

Thermal Oil's anticipated 2020 capital expenditures of $65 million focuses on Leismer including long-lead initiatives for Pad L8, a water disposal well which is expected to reduce annual non-energy operating costs by $10 million and routine pump changes at both Leismer and Hangingstone. At Hangingstone, the Company will complete its first facility turnaround during the second quarter. Thermal Oil 2020 production is expected to average between 26,000 – 27,000 bbl/d.

Light Oil's anticipated 2020 capital expenditures of $60 million will be weighted toward the first half of 2020. In the Montney, the Company will finish the completion and tie-in of the two multi-well pads (10 gross wells) which are expected to be on stream in the first half of 2020. In the Duvernay, activity will include 7 (gross) drills, 13 (gross) completions and 16 (gross) tie-ins. Light Oil production is expected to average between 10,000 – 10,500 boe/d (55% liquids).

2020 Operational & Financial Guidance ($ millions, unless otherwise noted)	Annual
Corporate	
Production (boe/d)	36,000 - 37,500
% Liquids	~88%
Capital Expenditures Net of Capital-Carry(1)(2)	$125
Light Oil	
Production (boe/d)	10,000 - 10,500
Capital Expenditures Net of Capital-Carry(1)(2)	$60
Thermal Oil	
Production (bbl/d)	26,000 - 27,000
Capital expenditures(1)	$65

(1) Excludes capitalized staff costs.
(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

Athabasca's year-ended 2019 production results were consistent with guidance reported on November 5, 2019. 2019 corporate production averaged 36,196 boe/d and compared to guidance of 36,000 boe/d. 2019 capital expenditures (excluding capitalized staff costs) totaled $131.6 million relative to guidance of $135 million.

CONSOLIDATED RESULTS

For analysis of operating results see the Light Oil Division and Thermal Oil Division sections within this MD&A. For further details related to commodity risk management gains/losses see the Risk Management Contracts section.

Consolidated Operating Results

	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
PRODUCTION				
Oil and condensate (bbl/d)	3,793	5,820	4,507	4,714
Natural gas (Mcf/d)	23,695	34,309	28,281	33,104
Natural gas liquids (bbl/d)	899	1,071	918	1,049
Bitumen (bbl/d)	27,761	25,375	26,058	27,923
Total (boe/d)	36,403	37,984	36,196	39,203

($ Thousands, unless otherwise noted)	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
Petroleum and natural gas sales[1]	$ 188,101	$ 96,885	$ 855,097	$ 809,637
Royalties	(3,761)	(2,872)	(16,183)	(18,696)
Cost of diluent[1]	(68,428)	(88,021)	(286,957)	(413,525)
Operating expenses	(46,342)	(46,326)	(173,601)	(175,520)
Transportation and marketing	(24,625)	(22,089)	(101,156)	(84,083)
	$ 44,945	$ (62,423)	$ 277,200	$ 117,813
Realized gain (loss) on commodity risk management contracts	(2,064)	9,243	(43,981)	(23,695)
Consolidated Operating Income (Loss)[2]	$ 42,881	$ (53,180)	$ 233,219	$ 94,118
REALIZED PRICES				
Oil and condensate ($/bbl)	$ 67.38	$ 45.47	$ 67.21	$ 68.02
Natural gas ($/Mcf)	2.82	3.06	2.55	2.78
Natural gas liquids ($/bbl)	27.21	34.89	30.28	47.95
Blended bitumen sales ($/bbl)	48.55	17.19	54.35	43.81
Realized price (net of cost of diluent) ($/boe)	38.61	2.47	43.70	27.46
Royalties ($/boe)	(1.21)	(0.80)	(1.24)	(1.30)
Operating expenses ($/boe)	(14.95)	(12.89)	(13.35)	(12.17)
Transportation and marketing ($/boe)	(7.94)	(6.15)	(7.78)	(5.83)
	$ 14.51	$ (17.37)	$ 21.33	$ 8.16
Realized gain (loss) on commodity risk mgmt. contracts ($/boe)	(0.67)	2.57	(3.38)	(1.64)
CONSOLIDATED OPERATING NETBACK[2] ($/boe)	$ 13.84	$ (14.80)	$ 17.95	$ 6.52

(1) Includes intercompany condensate sold by the Light Oil segment to the Thermal Oil segment for use as diluent that is eliminated on consolidation.
(2) Refer to the “Advisories and Other Guidance” section within this MD&A for additional information on Non-GAAP Financial Measures.

Consolidated Segments Income (Loss)

($ Thousands)	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
Consolidated Operating Income (Loss)[1]	$ 42,881	$ (53,180)	$ 233,219	$ 94,118
Unrealized gain (loss) on commodity risk management contracts	(3,634)	(15,623)	(2,437)	(8,155)
Impairments	—	(356,674)	—	(356,674)
Depletion and depreciation	(30,883)	(39,537)	(128,854)	(160,466)
Gain (loss) on sale of assets	105	—	222,653	—
Exploration expenses	(384)	(168)	(2,330)	(960)
CONSOLIDATED SEGMENTS INCOME (LOSS)	$ 8,085	$ (465,182)	$ 322,251	$ (432,137)

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

Consolidated Capital Expenditures

($ Thousands)	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
Light Oil Division	$ 46,473	$ 39,569	$ 109,687	$ 192,495
Thermal Oil Division	23,229	25,703	89,343	83,696
Corporate assets	94	127	111	137
TOTAL CAPITAL EXPENDITURES[1]	$ 69,796	$ 65,399	$ 199,141	$ 276,328
Less: Greater Kaybob capital-carry	(23,537)	(19,357)	(58,934)	(82,348)
TOTAL CAPITAL EXPENDITURES NET OF CAPITAL-CARRY[2]	$ 46,259	$ 46,042	$ 140,207	$ 193,980

(1) For the three months and year ended December 31, 2019, capital expenditures include $2.1 million and $8.6 million of capitalized cash staff costs, respectively (December 31, 2018 - $2.7 million, $11.7 million).

(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

LIGHT OIL DIVISION

Athabasca produces light oil and liquids-rich natural gas from unconventional reservoirs. Development has been focused on the Montney in the Greater Placid area and the Duvernay in the Greater Kaybob area near the town of Fox Creek, Alberta. As at December 31, 2019, the Light Oil Division had approximately 72 MMboe of Proved plus Probable Reserves[1]. Athabasca's Light Oil Division assets are supported by operated regional infrastructure primarily consisting of four batteries and a network of gas pipelines which connect the facilities to two regional third party gas processing plants.

In Greater Placid, Athabasca has a 70% operated working interest in approximately 80,000 gross Montney acres. Athabasca has transitioned Greater Placid from early stage resource capture to efficient multi-well pad development. An inventory of approximately 200[2] gross drilling locations positions the Company for multi-year growth in this area.

In Greater Kaybob, Athabasca has a 30% non-operated interest in approximately 220,000 gross acres of commercially prospective Duvernay lands with exposure to both liquids-rich gas and volatile oil opportunities and an inventory of approximately 700[2] gross extended reach drilling locations. Seventy-five percent of Athabasca’s Greater Kaybob development capital is currently funded by its joint venture partner under a multi-year $219 million (undiscounted) capital-carry commitment which was designed to support approximately $1 billion of gross Duvernay investment. The capital-carry balance remaining at December 31, 2019 was $22.7 million (undiscounted).

(1) Based on the report of Athabasca's independent reserve evaluator effective December 31, 2019. Refer to the "Advisories and Other Guidance" section within this MD&A and the AIF for additional information about the Company's reserves and resources.

(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information regarding the Company's drilling locations.

Light Oil Operating Results

	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
PRODUCTION				
Oil and condensate (bbl/d)	3,793	5,820	4,507	4,714
Natural gas (Mcf/d)	23,695	34,309	28,281	33,104
Natural gas liquids (bbl/d)	899	1,071	918	1,049
Total (boe/d)	8,642	12,609	10,138	11,280
Consisting of:				
Greater Placid area (boe/d)	4,571	7,549	5,680	7,553
% liquids	43%	51%	44%	46%
Greater Kaybob area (boe/d)	4,071	5,060	4,458	3,727
% liquids	67%	59%	65%	62%

($ Thousands, unless otherwise noted)	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
Petroleum and natural gas sales	$ 31,904	$ 37,434	$ 146,980	$ 169,017
Royalties	(1,273)	(1,575)	(4,638)	(6,304)
Operating expenses	(8,719)	(8,332)	(26,234)	(33,826)
Transportation and marketing	(5,625)	(5,406)	(21,104)	(21,743)
Light Oil Operating Income (Loss)[1]	$ 16,287	$ 22,121	$ 95,004	$ 107,144
REALIZED PRICES				
Oil and condensate ($/bbl)	$ 67.38	$ 45.47	$ 67.21	$ 68.02
Natural gas ($/Mcf)	2.82	3.06	2.55	2.78
Natural gas liquids ($/bbl)	27.21	34.89	30.28	47.95
Realized price ($/boe)	40.13	32.27	39.72	41.05
Royalties ($/boe)	(1.60)	(1.36)	(1.25)	(1.53)
Operating expenses ($/boe)	(10.97)	(7.18)	(7.09)	(8.22)
Transportation and marketing ($/boe)	(7.07)	(4.66)	(5.70)	(5.28)
LIGHT OIL OPERATING NETBACK[1] ($/boe)	$ 20.49	$ 19.07	$ 25.68	$ 26.02

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

Athabasca's Light Oil production averaged 8,642 boe/d and 10,138 boe/d during the fourth quarter and year ended December 31, 2019, decreases of 31% and 10%, respectively, from the comparable 2018 periods. Production decreases were primarily the result of natural production declines in the Greater Placid Duvernay area with no new wells tied in since the fall of 2018, partially offset by joint venture activity in the Greater Kaybob Duvernay area (10 gross wells at a 30% working interest).

Athabasca’s Light Oil Operating Netback was $20.49/boe during the fourth quarter of 2019, an increase of 7% from the comparable period in 2018 primarily due to higher Canadian benchmark oil prices, partially offset by higher transportation costs due to the fixed nature of the fees spread over lower production and higher operating expenses related to prior period adjustments. Athabasca’s Light Oil Operating Netback was $25.68/boe in 2019, in line with a $26.02/boe netback in 2018.

Athabasca generated Light Oil Operating Income of $16.3 million in the fourth quarter of 2019 and $95.0 million for 2019, decreases of 26% and 11% respectively from the comparable 2018 periods primarily due to lower production volumes.

Light Oil Segment Income (Loss)

($ Thousands)	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
Light Oil Operating Income (Loss)(1)	$ 16,287	$ 22,121	$ 95,004	$ 107,144
Depletion and depreciation	(16,278)	(21,775)	(71,322)	(74,188)
Gain (loss) on sale of assets	—	—	(1,205)	—
Exploration expenses	—	(26)	—	(66)
LIGHT OIL SEGMENT INCOME (LOSS)	$ 9	$ 320	$ 22,477	$ 32,890

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

Depletion and depreciation decreased $5.5 million in the fourth quarter and $2.9 million in 2019 compared to the same periods in the prior year primarily due to lower production volumes, partially offset by a higher depletion rate.

Light Oil Capital Expenditures

($ Thousands)	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
Greater Placid	$ 14,953	$ 13,482	$ 30,214	$ 83,260
Greater Kaybob	31,520	26,087	79,473	109,235
TOTAL LIGHT OIL CAPITAL EXPENDITURES(1)(2)	$ 46,473	$ 39,569	$ 109,687	$ 192,495
Less: Greater Kaybob capital-carry	(23,537)	(19,357)	(58,934)	(82,348)
TOTAL CAPITAL EXPENDITURES NET OF CAPITAL-CARRY(3)	$ 22,936	$ 20,212	$ 50,753	$ 110,147

(1) For the three months and year ended December 31, 2019, capital expenditures include $0.9 million and $3.8 million of capitalized cash staff costs, respectively (December 31, 2018 - $1.2 million, $5.0 million).
(2) Includes $7.0 million of net land acquisition expenditures in 2019.
(3) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

Including recovery of the capital-carry, Athabasca's net cash outflow from capital expenditures in Greater Kaybob was $8.0 million and $20.5 million for the three months and year ended December 31, 2019, respectively (December 31, 2018 - $6.7 million, $26.9 million).

During the year ended December 31, 2019, Light Oil capital expenditures of $109.7 million were primarily incurred for drilling and completions. The following table summarizes Athabasca's well activity for the three months and year ended December 31, 2019 and 2018:

	Three months ended December 31,				Year ended December 31,			
	2019		2018		2019		2018	
Well activity(1)	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Greater Placid								
Wells drilled	4	2.8	5	3.5	4	2.8	13	9.1
Wells completed	3	2.1	—	—	3	2.1	11	7.7
Wells brought on production	—	—	6	4.2	—	—	11	7.7
Greater Kaybob								
Wells drilled	9	2.4	2	0.6	18	5.1	25	7.5
Wells completed	3	0.8	4	1.2	14	4.1	23	6.9
Wells brought on production	—	—	5	1.5	10	3.0	26	7.8

(1) Drilling counts are based on rig release date and brought on production counts are based on first production date of in-line test or tie-in to permanent facilities.

THERMAL OIL DIVISION

Overview

Athabasca's Thermal Oil Division consists of two producing oil sands projects and a large resource base of expansion and exploration areas in the Athabasca region of northeastern Alberta. The Thermal Oil Division underpins Athabasca's low corporate production decline and low sustaining capital requirements, supporting significant free cash flow potential.

Athabasca has a 100% working interest in the producing Leismer Thermal Oil Project (the "Leismer Project") and the delineated Corner lease. The Leismer Project was commissioned in 2010 and has proven reserves in place to support a flat production profile for approximately 45 years and a reserve life index of over 90 years (proved plus probable). The Leismer Project has Proved plus Probable Reserves of approximately 695 MMbbl(1) and 0.3 billion barrels (risked)(1) (0.4 billion barrels unrisked)(1) of Best Estimate Development Pending Contingent Resources. The Corner lease has Proved plus Probable Reserves of approximately 353 MMbbl(1) and 0.4 billion barrels (risked)(1) (0.5 billion barrels unrisked)(1) of Best Estimate Development Pending Contingent Resources. The Leismer Project and Corner assets have received regulatory approval for future development phases of up to a combined 80,000 bbl/d.

Athabasca also has a 100% working interest in the producing Hangingstone Thermal Oil Project (the "Hangingstone Project"). The Hangingstone Project was commissioned in July 2015 and has proven reserves in place to support a flat production profile for approximately 25 years and a reserve life index of over 50 years (proved plus probable). Hangingstone has Proved plus Probable Reserves of approximately 177 MMbbl(1). Minimal development and maintenance capital will be required in the near-term to maintain Hangingstone production.

Athabasca's Thermal Oil exploration areas consist of Dover West Leduc Carbonates, Dover West Sands, Birch and Grosmont, with oil sands prospectivity in the McMurray and Wabiskaw formations as well as carbonates in the Leduc and Grosmont formations.

Athabasca's Thermal Oil Division has access to multiple sales points with marketing agreements on the Enbridge Waupisoo transportation pipeline. In the third quarter of 2019, the Company secured approximately 7,200 bbl/d of blended bitumen capacity on the existing Keystone pipeline diversifying its end market access to the US Gulf Coast. The Company has secured 8,000 bbl/d of direct refinery sales for 2020 which mitigates apportionment risk on the Enbridge Mainline. Longer term, Athabasca has secured 20,000 bbl/d of blended bitumen capacity on the Trans Mountain pipeline expansion and 25,000 bbl/d of blended bitumen capacity on the Keystone XL pipeline which will further diversify the Company's access to multiple end markets.

Leismer Infrastructure Transaction

On December 10, 2018, Athabasca entered into an agreement to sell its Leismer pipelines and Cheecham storage terminal ("Leismer Infrastructure Transaction") for $265.0 million. The Leismer Infrastructure Transaction was completed on January 15, 2019 and provides Athabasca with priority service on the pipelines and access to the dilbit/diluent tanks at Cheecham for an annual toll of approximately $26.0 million, with a discounted toll for any excess volumes.

Upon close of the transaction, Athabasca received $265.0 million of cash consideration and incurred $2.8 million of transaction costs, resulting in net proceeds of $262.2 million. Athabasca de-recognized $39.9 million of PP&E and $0.4 million in decommissioning obligations resulting in a gain of $222.8 million on the Leismer Infrastructure Transaction.

(1) Based on the report of Athabasca's independent reserve evaluator effective December 31, 2019. Refer to the "Advisories and Other Guidance" section within this MD&A and the AIF for additional information about the Company's reserves and resources.

Leismer Operating Results

	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
VOLUMES				
Bitumen production (bbl/d)	19,296	17,315	17,565	18,926
Bitumen sales (bbl/d)	18,462	17,196	17,402	19,033
Blended bitumen sales (bbl/d)	25,506	24,113	24,006	26,662

($ Thousands, unless otherwise noted)	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
Blended bitumen sales	$ 114,093	$ 41,490	$ 475,613	$ 425,474
Cost of diluent	(48,038)	(54,433)	(184,076)	(270,149)
Total bitumen sales	66,055	(12,943)	291,537	155,325
Royalties	(1,979)	(967)	(8,422)	(8,946)
Operating expenses - non-energy	(16,272)	(13,267)	(63,739)	(53,370)
Operating expenses - energy	(9,138)	(6,019)	(28,660)	(22,296)
Transportation and marketing	(10,898)	(5,413)	(42,447)	(21,616)
Leismer Operating Income (Loss)(1)	$ 27,768	$ (38,609)	$ 148,269	$ 49,097
REALIZED PRICE				
Blended bitumen sales ($/bbl)	$ 48.62	$ 18.70	$ 54.28	$ 43.72
Bitumen sales ($/bbl)	$ 38.89	$ (8.18)	$ 45.90	$ 22.36
Royalties ($/bbl)	(1.17)	(0.61)	(1.33)	(1.29)
Operating expenses - non-energy ($/bbl)	(9.58)	(8.39)	(10.03)	(7.68)
Operating expenses - energy ($/bbl)	(5.38)	(3.80)	(4.51)	(3.21)
Transportation and marketing ($/bbl)	(6.42)	(3.42)	(6.68)	(3.11)
LEISMER OPERATING NETBACK(1) ($/bbl)	$ 16.34	$ (24.40)	$ 23.35	$ 7.07

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

Leismer production in the fourth quarter of 2019 was 19,296 bbl/d, an increase of 11% compared to the fourth quarter of 2018. Production in the fourth quarter of 2018 was voluntarily curtailed in response to unprecedented WCS differentials during that period. Production growth in the fourth quarter of 2019 was due to the start-up of Pad 7. Pad 7 is composed of five well pairs, each with approximately 1,250 meter laterals. Steaming commenced in June and all five well pairs were converted to production throughout the second half of 2019. Annual production was 7% lower than the previous year due to the mandated government curtailments early in the year and facility maintenance during the second quarter.

The Leismer Operating Netback was $16.34/bbl during the fourth quarter of 2019 compared to $(24.40)/bbl in the fourth quarter of 2018 primarily due to higher WCS benchmark oil prices. During 2019, the Leismer Operating Netback was $23.35/bbl compared to $7.07/bbl in 2018, increasing primarily as a result of higher WCS benchmark oil prices and lower diluent costs, partially offset by higher operating and transportation expenses.

Total operating expenses were $14.96/bbl in the fourth quarter of 2019 and $14.54/bbl in 2019, compared to $12.19/bbl and $10.89/bbl in the comparable periods of 2018. Non-energy costs per bbl in 2019 have increased relative to the prior year primarily due to higher short-term water disposal costs and maintenance costs. A disposal well project is currently underway which is expected to reduce non-energy operating costs in 2020. Energy operating costs per barrel in 2019 were higher relative to the prior year primarily due to higher gas and power prices.

Transportation and marketing expenses have increased in 2019 relative to 2018 primarily due to the new pipeline and storage tolls incurred by Athabasca following the Leismer Infrastructure Transaction.

Seasonality can have an impact on Operating Income (Loss) generated by the Thermal Oil business. In the first and fourth quarters of a given year, dilution costs will generally increase as more diluent is required to meet pipeline specifications.

Hangingstone Operating Results

	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
VOLUMES				
Bitumen production (bbl/d)	8,465	8,060	8,493	8,997
Bitumen sales (bbl/d)	6,587	9,266	8,076	9,203
Blended bitumen sales (bbl/d)	9,466	13,489	11,691	13,396

($ Thousands, unless otherwise noted)	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
Blended bitumen sales	$ 42,104	$ 17,961	$ 232,504	$ 215,146
Cost of diluent	(20,390)	(33,588)	(102,881)	(143,376)
Total bitumen sales	21,714	(15,627)	129,623	71,770
Royalties	(509)	(330)	(3,123)	(3,446)
Operating expenses - non-energy	(7,294)	(13,200)	(35,399)	(46,933)
Operating expenses - energy	(4,919)	(5,508)	(19,569)	(19,095)
Transportation and marketing	(8,102)	(11,270)	(37,605)	(40,724)
Hangingstone Operating Income (Loss)[1]	$ 890	$ (45,935)	$ 33,927	$ (38,428)
REALIZED PRICE				
Blended bitumen sales ($/bbl)	$ 48.35	$ 14.47	$ 54.49	$ 44.00
Bitumen sales ($/bbl)	$ 35.83	$ (18.33)	$ 43.97	$ 21.37
Royalties ($/bbl)	(0.84)	(0.39)	(1.06)	(1.03)
Operating expenses - non-energy ($/bbl)	(12.04)	(15.48)	(12.01)	(13.97)
Operating expenses - energy ($/bbl)	(8.12)	(6.46)	(6.64)	(5.68)
Transportation and marketing ($/bbl)	(13.37)	(13.22)	(12.76)	(12.12)
HANGINGSTONE OPERATING NETBACK[1] ($/bbl)	$ 1.46	$ (53.88)	$ 11.50	$ (11.43)

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

Hangingstone production in the fourth quarter was 8,465 bbl/d, an increase of 5% compared to the fourth quarter of 2018. Production in the fourth quarter of 2018 was voluntarily curtailed in response to unprecedented WCS differentials during that period. 2019 production was 6% lower than 2018, impacted by reservoir recovery following curtailments and facility downtime.

Hangingstone realized an Operating Netback of $1.46/bbl in the fourth quarter of 2019 compared to $(53.88)/bbl in the fourth quarter of 2018, primarily due to higher WCS benchmark oil prices. The Hangingstone Operating Netback was $11.50/bbl in 2019 compared to $(11.43)/bbl in 2018, primarily due to higher WCS benchmark oil prices and lower diluent costs.

Total operating expenses in the fourth quarter and 2019 were 8% and 5% lower, respectively, from the comparable 2018 periods. Non-energy costs per bbl decreased in 2019 primarily due to the optimization of field operations over the past year. Energy operating costs per bbl in 2019 were higher than the prior year primarily due to higher gas and power prices.

Seasonality can have an impact on Operating Income (Loss) generated by the Thermal Oil business. In the first and fourth quarters of a given year, dilution costs will generally increase as more diluent is required to meet pipeline specifications.

Consolidated Thermal Oil Operating Results

	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
VOLUMES				
Bitumen production (bbl/d)	27,761	25,375	26,058	27,923
Bitumen sales (bbl/d)	25,049	26,462	25,478	28,236
Blended bitumen sales (bbl/d)	34,972	37,602	35,697	40,058

($ Thousands, unless otherwise noted)	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
Blended bitumen sales	$ 156,197	$ 59,451	$ 708,117	$ 640,620
Cost of diluent	(68,428)	(88,021)	(286,957)	(413,525)
Total bitumen sales	87,769	(28,570)	421,160	227,095
Royalties	(2,488)	(1,297)	(11,545)	(12,392)
Operating expenses - non-energy	(23,566)	(26,467)	(99,138)	(100,303)
Operating expenses - energy	(14,057)	(11,527)	(48,229)	(41,391)
Transportation and marketing	(19,000)	(16,683)	(80,052)	(62,340)
Thermal Oil Operating Income (Loss)(1)	$ 28,658	$ (84,544)	$ 182,196	$ 10,669
REALIZED PRICE				
Blended bitumen sales ($/bbl)	$ 48.55	$ 17.19	$ 54.35	$ 43.81
Bitumen sales ($/bbl)	$ 38.09	$ (11.74)	$ 45.29	$ 22.03
Royalties ($/bbl)	(1.08)	(0.53)	(1.24)	(1.20)
Operating expenses - non-energy ($/bbl)	(10.23)	(10.87)	(10.66)	(9.73)
Operating expenses - energy ($/bbl)	(6.10)	(4.73)	(5.19)	(4.02)
Transportation and marketing ($/bbl)	(8.24)	(6.85)	(8.61)	(6.05)
THERMAL OIL OPERATING NETBACK(1) ($/bbl)	$ 12.44	$ (34.72)	$ 19.59	$ 1.03

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

Thermal Oil Segment Income (Loss)

($ Thousands)	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
Thermal Oil Operating Income (Loss)(1)	$ 28,658	$ (84,544)	$ 182,196	$ 10,669
Impairment loss	—	(356,674)	—	(356,674)
Depletion and depreciation	(14,605)	(17,762)	(57,532)	(86,278)
Gain (loss) on sale of assets	105	—	223,858	—
Exploration expenses	(384)	(142)	(2,330)	(894)
THERMAL OIL SEGMENT INCOME (LOSS)	$ 13,774	$ (459,122)	$ 346,192	$ (433,177)

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.

Depletion and depreciation expense decreased $3.2 million in the fourth quarter of 2019 and $28.7 million in 2019 compared to the same periods in the prior year primarily due to a decrease in the Hangingstone depletion rate.

During the first quarter of 2019, Athabasca recorded a gain of $222.8 million on the Leismer Infrastructure Transaction.

During the fourth quarter of 2018, Athabasca recognized an impairment loss of $356.7 million relating to its Hangingstone and Dover West assets.

Thermal Oil Capital Expenditures

($ Thousands)	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
Leismer Project	$ 19,382	$ 22,312	$ 79,430	$ 70,535
Hangingstone Project	3,774	2,897	9,592	10,148
Other Thermal Oil exploration	73	494	321	3,013
TOTAL THERMAL OIL CAPITAL EXPENDITURES(1)	$ 23,229	$ 25,703	$ 89,343	$ 83,696

(1) For the three months and year ended December 31, 2019, capital expenditures include $1.2 million and $4.8 million of capitalized staff costs, respectively (December 31, 2018 - $1.5 million, $6.7 million).

Thermal Oil capital expenditures of $89.3 million in 2019 were primarily associated with the drilling and completions of five well pairs and four observation wells on Pad 7, a steam debottleneck project at Leismer which will provide future operational flexibility and regular downhole pump replacements at both assets. During 2019, engineering, long leads and civil work on five well pairs and four observation wells on Pad 8 were also incurred.

In 2019, Athabasca received two government grants to support funding of certain capital projects designed to reduce the emissions intensity of Athabasca's assets and recognized $4.6 million related to these grants.

CORPORATE REVIEW

Liquidity and Capital Resources

Funding

Balance sheet strength and flexibility is a key priority for Athabasca and the Company's objectives in managing capital are ensuring it has sufficient funding to sustain its core operating properties and a resilient balance sheet with sufficient liquidity. The Company expects to achieve this objective through prudent capital spending, an active commodity risk management program and by maintaining sufficient funds for anticipated short-term spending and to manage periods of volatility within its cash, cash equivalent and short-term investment accounts as well as through available credit facilities.

As at December 31, 2019, Athabasca had liquidity of $362.9 million, including $254.4 million of unrestricted cash and cash equivalents, $80.6 million of available credit under its Credit Facility (defined below), and $5.2 million of available credit under its Unsecured Letter of Credit Facility (defined below). In addition, the Company had $22.7 million (undiscounted) of funding available through the capital-carry receivable.

In 2020, it is anticipated that Athabasca's Light Oil and Thermal Oil capital and operating activities will be funded through cash flow from operating activities, the capital-carry receivable, existing cash and cash equivalents and available credit facilities. Beyond 2020, depending on the Company's level of capital spend and the commodity price environment, the Company may require additional funding which could include debt, equity, joint ventures, asset sales or other external financing. The availability of any additional future funding will depend on, among other things, the current commodity price environment, operating performance, the Company's credit rating and the current availability of the equity and debt capital markets.

Indebtedness

As at ($ Thousands)	December 31, 2019	December 31, 2018
2022 Notes(1)	$ 583,425	$ 614,070
Debt issuance costs	(47,081)	(47,081)
Amortization of debt issuance costs	23,343	14,151
TOTAL LONG-TERM DEBT	$ 559,687	$ 581,140

(1) As at December 31, 2019, the US dollar denominated 2022 Notes were translated into Canadian dollars at the period end exchange rate of US$1.00 = C$1.2965.

Athabasca had the following debt instruments and credit facilities in place as at December 31, 2019:

2022 Notes

On February 24, 2017 Athabasca issued US$450.0 million of Senior Secured Second Lien Notes (the "2022 Notes"). The 2022 Notes bear interest at a rate of 9.875% per annum, payable semi-annually, and mature on February 24, 2022. Athabasca may redeem the 2022 Notes at the following specified redemption prices:

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

Credit Facility

In the fourth quarter of 2019, Athabasca renewed its $120.0 million reserve-based credit facility (the "Credit Facility"). The Credit Facility is a 364 day committed facility available on a revolving basis until May 31, 2020, at which time it may be extended at the lenders' option. If the revolving period is not extended, the undrawn portion of the facility will be cancelled and any amounts outstanding would be repayable at the end of the non-revolving term, being May 31, 2021. The Credit Facility is subject to a semi-annual borrowing base review, occurring approximately in May and November of each year. The borrowing base is determined based on the lender's evaluation of the Company's petroleum and natural gas reserves and their commodity price outlook at the time of each renewal, which could result in an increase or a reduction to the Credit Facility.

As at December 31, 2019, amounts borrowed under the Credit Facility bear interest at a floating rate based on the applicable Canadian prime rate, US base rate, LIBOR or bankers' acceptance rate, plus a margin of 2.5% to 3.5%. The Company incurs an issuance fee for letters of credit of 3.5% and a standby fee on the undrawn portion of the Credit Facility of 0.8%. As at December 31, 2019, the Company had no amounts drawn and had $39.4 million of letters of credit issued and drawn under the Credit Facility. As at December 31, 2018, the Company had no amounts drawn or letters of credit issued and drawn under the Credit Facility.

Cash-Collateralized Letter of Credit Facility

Athabasca maintains a $110.0 million cash-collateralized letter of credit facility (the "Letter of Credit Facility") with a Canadian bank for issuing letters of credit to counterparties. The facility is available on a demand basis and letters of credit issued under the Letter of Credit Facility incur an issuance fee of 0.25%. As at December 31, 2019, Athabasca had $109.5 million (December 31, 2018 - $110.0 million) in letters of credit issued and drawn under the Letter of Credit Facility.

Under the terms of the Letter of Credit Facility, Athabasca is required to contribute cash to a cash-collateral account equivalent to 101% of the value of all letters of credit issued under the facility. As at December 31, 2019, $110.6 million of restricted cash was held in the cash-collateral account (December 31, 2018 - $111.1 million).

Unsecured Letter of Credit Facility

Athabasca maintains a $30.0 million unsecured letter of credit facility (the "Unsecured Letter of Credit Facility") with a Canadian bank which is supported by a performance security guarantee from Export Development Canada. The facility is available on a demand basis and letters of credit issued under this facility incur an issuance and performance guarantee fee of 2.5%. As at December 31, 2019, the Company had $24.8 million of letters of credit issued and drawn under the Unsecured Letter of Credit Facility (December 31, 2018 - $18.5 million).

Financing and Interest

($ Thousands)	Three months ended December 31, 2019	Three months ended December 31, 2018	Year ended December 31, 2019	Year ended December 31, 2018
Financing and interest expense on indebtedness	$ 15,396	$ 15,129	$ 61,118	$ 60,242
Amortization of debt issuance costs	2,527	2,278	9,387	8,627
Accretion of provisions	2,991	2,957	11,608	11,566
Interest expense on lease liability	409	—	1,726	—
TOTAL FINANCING AND INTEREST	$ 21,323	$ 20,364	$ 83,839	$ 80,435

During the three months and year ended December 31, 2019 and 2018, financing and interest expenses were primarily attributable to the Company's 2022 Notes. The interest expense on the lease liability relates to the adoption of IFRS 16 *Leases* on January 1, 2019 which resulted in a new implied interest expense of $0.4 million and $1.7 million during the three months and year ended December 31, 2019, respectively.

Foreign Exchange Gain (Loss), Net

($ Thousands)	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
Unrealized foreign exchange gain (loss)	$ 12,230	$ (32,523)	$ 30,320	$ (48,729)
Realized foreign exchange gain (loss)	(1,029)	(759)	(321)	(1,140)
FOREIGN EXCHANGE GAIN (LOSS), NET	$ 11,201	$ (33,282)	$ 29,999	$ (49,869)

Athabasca is exposed to foreign currency risk primarily on the principal and interest components of its US dollar denominated 2022 Notes. The net foreign exchange gains (losses) recognized were primarily due to unrealized gains (losses) on the note principal as the value of the Canadian dollar fluctuates relative to the US dollar.

Risk Management Contracts

Under the Company's commodity risk management program, Athabasca may utilize financial and/or physical delivery contracts to fix the commodity price associated with a portion of its future production in order to manage its exposure to fluctuations in commodity prices.

Financial commodity risk management contracts are valued on the consolidated balance sheet by multiplying the contractual volumes by the differential between the anticipated market price (forecasted strip price) and the contractual fixed price at each future settlement date. The corresponding change in the asset or liability is recognized as an unrealized gain or loss in net income (loss). As the commodity derivatives are unwound (i.e. settled in cash), Athabasca recognizes a corresponding realized gain or loss in net income (loss). Physical delivery contracts are not considered financial instruments and therefore, no asset or liability is recognized on the consolidated balance sheet.

Athabasca is also exposed to foreign exchange risk on the principal and interest components of its US dollar denominated 2022 Notes and may utilize financial contracts to reduce its exposure to foreign currency risk.

Financial commodity risk management contracts

As at December 31, 2019, the following financial commodity risk management contracts were in place:

Instrument	Period	Volume	C$ Average Price/bbl[1]	US$ Average Price/bbl[1]
WTI fixed price swaps	January - March 2020	9,000 bbl/d	$ 73.19	$ 56.45
WTI/WCS differential swaps	January - March 2020	9,659 bbl/d	$ (26.14)	$ (20.16)
WTI three way collar	January - March 2020	6,000 bbl/d	$ 64.28|72.39|78.87	$ 49.58|55.83|60.83
WTI fixed price swaps	April - June 2020	6,000 bbl/d	$ 71.37	$ 55.05
WTI/WCS differential swaps	April - June 2020	9,000 bbl/d	$ (24.55)	$ (18.93)
WTI three way collar	April - June 2020	9,000 bbl/d	$ 66.63|74.19|80.78	$ 51.39|57.22|62.31
WTI fixed price swaps	July - September 2020	3,000 bbl/d	$ 71.34	$ 55.03
WTI/WCS differential swaps	July - September 2020	7,000 bbl/d	$ (25.62)	$ (19.76)
WTI three way collar	July - September 2020	6,000 bbl/d	$ 64.28|72.39|78.87	$ 49.58|55.83|60.83
WTI fixed price swaps	October - December 2020	3,000 bbl/d	$ 71.34	$ 55.03
WTI/WCS differential swaps	October - December 2020	7,000 bbl/d	$ (25.62)	$ (19.76)
WTI three way collar	October - December 2020	6,000 bbl/d	$ 64.28|72.39|78.87	$ 49.58|55.83|60.83

(1) The implied C$ or US$ Average Price/bbl, as applicable, was calculated using the December 31, 2019 exchange rate of US$1.00 = C$1.2965.

The following table summarizes the Company's net gain (loss) on commodity risk management contracts for the three months and year ended December 31, 2019 and 2018:

($ Thousands)	Three months ended December 31, 2019	Three months ended December 31, 2018	Year ended December 31, 2019	Year ended December 31, 2018
Unrealized gain (loss) on commodity risk management contracts	$ (3,634)	$ (15,623)	$ (2,437)	$ (8,155)
Realized gain (loss) on commodity risk management contracts	(2,064)	9,243	(43,981)	(23,695)
GAIN (LOSS) ON COMMODITY RISK MANAGEMENT CONTRACTS, NET	$ (5,698)	$ (6,380)	$ (46,418)	$ (31,850)

The following table summarizes the sensitivity to price changes for Athabasca's commodity risk management contracts:

As at December 31, 2019	Change in WTI Increase of US$5.00/bbl	Change in WTI Decrease of US$5.00/bbl	Change in WCS differential Increase of US$1.00/bbl	Change in WCS differential Decrease of US$1.00/bbl
Increase (decrease) to fair value of commodity risk management contracts	$ (20,647)	$ 22,187	$ 3,715	$ (3,705)

Additional financial commodity risk management activity related to 2020 has taken place subsequent to December 31, 2019, as noted in the table below:

Instrument	Period	Volume	C$ Average Price/bbl(1)	US$ Average Price/bbl(1)
WTI fixed price swaps	January - March 2020	3,000 bbl/d	$ 79.45	$ 61.28
WTI fixed price swaps	April - June 2020	3,000 bbl/d	$ 79.45	$ 61.28
WTI/WCS differential swaps	April - June 2020	9,000 bbl/d	$ (22.04)	$ (17.00)
WTI/WCS differential swaps	July - September 2020	9,000 bbl/d	$ (21.06)	$ (16.24)
WTI/WCS differential swaps	October - December 2020	4,000 bbl/d	$ (21.57)	$ (16.64)

(1) The implied C$ or US$ Average Price/bbl, as applicable, was calculated using the December 31, 2019 exchange rate of US$1.00 = C$1.2965.

Foreign exchange risk management contracts

As at December 31, 2019, Athabasca had no foreign exchange risk management contracts in place. As at December 31, 2018, Athabasca had a foreign exchange risk management asset of $2.5 million in respect of a foreign exchange risk management contract associated with the February 2019 interest payment on the Company's 2022 Notes.

The following table summarizes the net gain (loss) on foreign exchange risk management contracts:

	Three months ended December 31, 2019	Three months ended December 31, 2018	Year ended December 31, 2019	Year ended December 31, 2018
Unrealized gain (loss) on foreign exchange risk management contracts	$ —	$ 1,669	$ (2,495)	$ 2,495
Realized gain (loss) on foreign exchange risk management contracts	—	—	1,733	1,071
GAIN (LOSS) ON FOREIGN EXCHANGE RISK MANAGEMENT CONTRACTS, NET	$ —	$ 1,669	$ (762)	$ 3,566

The net gain (loss) on foreign exchange risk management contracts is due to fluctuations in the USD/CAD forward exchange rates and the settlement of the contracts.

Commitments and Contingencies

The following table summarizes Athabasca's estimated future unrecognized minimum commitments as at December 31, 2019 for the following five years and thereafter:

($ Thousands)	2020	2021	2022	2023	2024	Thereafter	Total
Transportation and processing[(1)]	$ 125,933	$ 130,792	$ 144,275	$ 236,282	$ 233,748	$3,872,676	$4,743,706
Interest expense on long-term debt[(1)]	37,449	57,613	28,806	—	—	—	123,868
Purchase commitments and drilling rigs	5,181	—	—	—	—	—	5,181
TOTAL COMMITMENTS	$ 168,563	$ 188,405	$ 173,081	$ 236,282	$ 233,748	$3,872,676	$4,872,755

(1) Commitments which are denominated in US dollars were translated into Canadian dollars at the December 31, 2019 exchange rate of US$1.00 = C$1.2965.

In conjunction with the Leismer Infrastructure Transaction, Athabasca entered into a new multi-year transportation commitment. Amounts associated with this commitment have been included in the above table.

As disclosed previously, during the third quarter of 2019 Athabasca entered into a 20 year firm service transportation agreement for approximately 7,200 bbl/d of blended bitumen capacity on the existing Keystone pipeline and a development cost agreement in relation to the Keystone XL pipeline. This agreement provides for a US$48.0 million ($62.7 million) conditional payment, which is only payable if shipper agreements on the Keystone XL pipeline were terminated on or before January 31, 2020. In connection with such agreements, Athabasca provided $81.6 million in financial assurances, consisting of $32.4 million (US$25.0 million) of cash and $49.2 million of letters of credit. The Keystone XL project has not been cancelled however certain regulatory and technical matters have resulted in the extension of shipper agreements to no later than March 31, 2021. Athabasca is evaluating various options under the agreements in order to manage risk and capture value for the Company. Until those options are fully assessed, the conditional payment assurance is still in place.

The Company is, from time to time, involved in claims arising in the normal course of business. The Company is also currently undergoing income tax and partner related audits in the normal course of business. The final outcome of such claims and audits cannot be predicted with certainty, however, management concluded that it has appropriately assessed any impact to the consolidated financial statements.

Credit Risk

Credit risk is the risk of financial loss to Athabasca if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from Athabasca's cash balances, accounts receivables from petroleum and natural gas marketers and joint interest partners, the capital-carry receivable and risk management contract counterparties.

Athabasca's cash, cash equivalents and restricted cash are held with five counterparties, all of which were large reputable financial institutions, and management concluded that credit risk associated with these investments is low. Management concluded that collection risk of the outstanding accounts receivables and capital-carry receivable is low given the high credit quality of the Company's material counterparties. No material receivables were past due as at December 31, 2019. Athabasca's risk management contracts are held with five counterparties, all of which were large reputable financial institutions, and management concluded that credit risk associated with these risk management contracts is low.

Interest Rate Risk

The Company's exposure to interest rate fluctuations on interest earned on its floating rate cash, cash equivalents and restricted cash balance of $365.0 million (December 31, 2018 - $185.0 million), from a 1.0% change in interest rates, would be approximately $3.7 million for a 12 month period (year ended December 31, 2018 - $1.8 million). The Company is also exposed to interest rate fluctuations on its Credit Facility which is undrawn as at December 31, 2019. The 2022 Notes and letters of credit issued are subject to fixed interest rates and are not exposed to changes in interest rates.

Other Corporate Items

General and Administrative ("G&A")

($ Thousands, unless otherwise noted)		Three months ended December 31, 2019		2018		Year ended December 31, 2019		2018
TOTAL GENERAL AND ADMINISTRATIVE	$	6,202	$	6,975	$	22,645	$	29,962
G&A per boe	$	1.85	$	2.00	$	1.71	$	2.09

During the three months and year ended December 31, 2019, Athabasca's G&A expenses decreased compared to the same periods in the prior year, primarily due to lower employee costs resulting from staff reductions in 2018. G&A in 2019 was also impacted by the adoption of IFRS 16 *Leases* which resulted in decreases to G&A of $0.7 million and $2.8 million, respectively.

Stock Based Compensation

During the year ended December 31, 2019, stock-based compensation decreased to $6.8 million compared to $8.6 million in the prior year. The decrease was primarily due to a lower deferred share units expense in 2019 resulting from the lower share price as at December 31, 2019 compared to 2018.

Gain (Loss) on Revaluation of Provisions and Other, Net

($ Thousands)		Three months ended December 31, 2019		2018		Year ended December 31, 2019		2018
Contingent payment obligation gain (loss)	$	339	$	38,052	$	3,442	$	21,816
Capital-carry receivable gain (loss)		744		252		2,420		5,428
Other		(1,393)		30		(1,402)		1,793
GAIN (LOSS) ON REVALUATION OF PROVISIONS AND OTHER, NET	$	(310)	$	38,334	$	4,460	$	29,037

The gains or losses on revaluation of the contingent payment obligation are primarily due to fluctuations in forecasted prices for WTI. In early 2017, as part of the acquisition of the Leismer/Corner Thermal Oil assets, Athabasca agreed to a contingent payment obligation for a four-year term ending in 2020 which is triggered at oil prices above US$65/bbl WTI. The payments are determined annually and calculated on one-third of annual Leismer bitumen production multiplied by an oil price factor (yearly average US$WTI/bbl less US$65/bbl, adjusted for inflation since 2017). The payments are capped at $75.0 million annually. The contingent payment obligation is remeasured at each reporting period using an option pricing model with any gains or losses recognized in net income (loss). The option pricing model includes estimates regarding future WTI prices, foreign exchange rates, inflation rates and Leismer production volumes and is therefore subject to significant measurement uncertainty. The difference in the actual cash outflows associated with the obligation could be material.

Income Taxes

As at December 31, 2019 and 2018, Athabasca was in a net unrecognized deferred tax asset position. The deductible temporary differences in excess of taxable temporary differences are approximately $2.0 billion (December 31, 2018 - $2.0 billion). Since Athabasca has not recognized the benefit of these deductible temporary differences, no deferred tax recovery was recognized during the years ended December 31, 2019 and 2018. As at December 31, 2019, the Company has approximately $3.2 billion in tax pools, including approximately $2.1 billion in non-capital losses and exploration tax pools available for immediate deduction against future income. The non-capital losses begin to expire after 2025.

From time to time, Athabasca undergoes income tax audits in the normal course of business. The Company has received notice of reassessments from the Canada Revenue Agency ("CRA"). While the final outcome of such reassessments cannot be predicted with certainty, Athabasca has received legal advice that confirms its position as filed and believes it is likely to be successful in appealing the reassessments. As such, the Company has not recognized any provision in its consolidated financial statements with respect to the reassessments and has posted a $12.6 million deposit with the CRA while objecting the reassessments.

Environmental and Regulatory Risks Impacting Athabasca

Athabasca operates in jurisdictions that have regulated greenhouse gas (“GHG”) emissions and other air pollutants. While some regulations are in effect, further changes and amendments are at various stages of review, discussion and implementation. There is uncertainty around how any future federal legislation will harmonize with provincial regulation, as well as the timing and effects of regulations. Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulatory environment of the crude oil and natural gas industry in Canada. Such regulations impose certain costs and risks on the industry, and there remains some uncertainty with regard to the impacts of federal or provincial climate change and environmental laws and regulations, as Athabasca is unable to predict additional legislation or amendments that governments may enact in the future. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on the Company's assets, operations and cash flow.

Uncertainty around timing of future pipeline infrastructure due to regulatory and legislative delays is a significant risk to Athabasca and could have a material impact on future financial results. Additional information is available in Athabasca’s AIF that is filed on the Company’s SEDAR profile at www.sedar.com.

Off Balance Sheet Arrangements

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

Outstanding Share Data

As at December 31, 2019, there were 523.5 million common shares outstanding, an aggregate of 23.8 million restricted share units, performance share units and deferred shares units outstanding, and 8.4 million stock options outstanding. There were no material changes in these balances between December 31, 2019 and March 4, 2020.

During the three months and year ended December 31, 2019, Athabasca issued 0.1 million and 7.6 million common shares, respectively, in respect of the Company’s equity-settled share-based compensation plans.

SUMMARY OF QUARTERLY RESULTS

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

($ Thousands, unless otherwise noted)	2019 Q4	2019 Q3	2019 Q2	2019 Q1	2018 Q4	2018 Q3	2018 Q2	2018 Q1
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	56.96	56.45	59.82	54.90	58.81	69.50	67.90	62.87
WTI (C$/bbl)	75.19	74.56	80.11	72.97	77.70	90.84	87.67	79.53
Western Canadian Select (C$/bbl)	54.27	58.36	65.73	56.62	25.36	61.75	62.89	48.77
Edmonton Par (C$/bbl)	67.99	68.21	73.60	66.41	42.75	81.90	80.60	72.06
Edmonton Condensate (C5+) (C$/bbl)	69.22	68.03	74.46	66.60	59.73	87.01	88.87	79.74
AECO (C$/GJ)	2.35	0.87	0.98	2.49	1.48	1.13	1.12	1.97
Chicago Citygate (US$/MMBtu)	2.20	2.08	2.31	2.82	3.67	2.79	2.67	2.95
Foreign exchange (USD : CAD)	1.32	1.32	1.34	1.33	1.32	1.31	1.29	1.27
CONSOLIDATED								
Petroleum and natural gas production (boe/d)	36,403	35,257	33,958	39,206	37,984	40,612	37,658	40,572
Realized price (net of cost of diluent) ($/boe)	38.61	43.63	50.69	42.25	2.47	43.42	39.73	24.23
Petroleum and natural gas sales ($)(1)	188,101	216,338	224,531	226,127	96,885	253,404	251,369	207,979
Operating Income (Loss) ($)(2)	42,881	64,614	67,122	58,602	(53,180)	83,703	46,719	16,876
Operating Netback ($/boe)(2)	13.84	19.10	22.19	16.77	(14.80)	23.21	13.01	4.65
Capital expenditures ($)	69,796	42,664	33,717	52,964	65,399	74,509	54,159	82,261
Capital Expenditures Net of Capital-Carry ($)(2)	46,259	35,304	26,888	31,756	46,042	52,389	38,888	56,661
LIGHT OIL DIVISION								
Petroleum and natural gas production (boe/d)	8,642	10,023	10,210	11,712	12,609	10,135	11,872	10,495
Realized price ($/boe)	40.13	37.37	39.65	41.53	32.27	46.43	42.68	44.65
Petroleum and natural gas sales ($)	31,904	34,462	36,836	43,778	37,434	43,294	46,107	42,182
Operating Income (Loss) ($)(2)	16,287	21,800	25,637	31,280	22,121	29,795	30,936	24,292
Operating Netback ($/boe)(2)	20.49	23.64	27.59	29.67	19.07	31.95	28.64	25.72
Capital expenditures ($)	46,473	21,501	11,858	29,855	39,569	60,739	25,557	66,630
Capital Expenditures Net of Capital-Carry ($)(2)	22,936	14,141	5,029	8,647	20,212	38,619	10,286	41,030
THERMAL OIL DIVISION								
Bitumen production (bbl/d)	27,761	25,234	23,748	27,494	25,375	30,477	25,786	30,077
Bitumen sales volumes (bbl/d)	25,049	26,744	23,028	27,100	26,462	29,074	27,578	29,857
Realized bitumen price ($/bbl)	38.09	45.97	55.58	42.56	(11.74)	42.37	38.46	17.05
Blended bitumen sales ($)	156,197	181,876	187,695	182,349	59,451	210,110	205,262	165,797
Operating Income (Loss) ($)(2)	28,658	51,888	56,522	45,128	(84,544)	62,322	39,635	(6,744)
Operating Netback ($/bbl)(2)	12.44	21.09	26.97	18.50	(34.72)	23.30	15.79	(2.51)
Capital expenditures ($)	23,229	21,146	21,859	23,109	25,703	13,767	28,595	15,631
OPERATING RESULTS								
Cash flow from operating activities ($)	32,975	16,741	61,488	(18,572)	(2,253)	61,733	27,605	(3,241)
Adjusted Funds Flow ($)(2)	21,478	43,906	47,757	41,619	(75,296)	62,151	25,680	(6,360)
Net income (loss) ($)	(8,757)	(8,265)	57,091	206,796	(488,479)	31,419	(19,267)	(93,330)
Net income (loss) per share - basic ($)	(0.02)	(0.02)	0.11	0.40	(0.95)	0.06	(0.04)	(0.18)
BALANCE SHEET ITEMS								
Cash and cash equivalents ($)	254,389	255,433	292,851	272,240	73,898	128,340	93,293	128,915
Restricted cash ($)	110,609	110,629	111,092	106,385	111,056	114,216	114,212	111,778
Capital-carry receivable (discounted) ($)(3)	22,602	45,395	52,570	58,861	79,116	98,221	119,018	132,745
Total assets ($)	2,093,465	2,081,910	2,068,778	2,066,858	1,825,638	2,320,838	2,297,112	2,318,471
Long-term debt ($)(3)	559,687	569,750	560,538	570,411	581,140	546,505	554,279	541,460
Shareholders' equity ($)	1,220,062	1,227,214	1,232,912	1,172,954	965,949	1,452,946	1,418,587	1,434,345

(1) Includes intercompany condensate sold by the Light Oil segment to the Thermal Oil segment for use as diluent that is eliminated on consolidation.
(2) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.
(3) Balances include the current and long-term portions as reported in the consolidated balance sheets.

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

SELECTED ANNUAL INFORMATION

The following table provides a summary of selected annual information for the years ended 2019, 2018 and 2017:

($ Thousands, unless otherwise noted)		December 31, 2019		December 31, 2018		December 31, 2017
Petroleum and natural gas production (boe/d)		36,196		39,203		35,421
Petroleum and natural gas sales	$	836,933	$	809,637	$	784,032
Net income (loss) and comprehensive income (loss)	$	246,865	$	(569,657)	$	(209,407)
per share (basic and diluted)	$	0.47	$	(1.11)	$	(0.42)
Cash flow from operating activities	$	92,632	$	83,844	$	61,697
per share (basic)	$	0.18	$	0.16	$	0.12
Adjusted Funds Flow(1)	$	154,760	$	6,175	$	102,123
per share (basic)	$	0.30	$	0.01	$	0.20
Capital expenditures(2)	$	199,141	$	276,328	$	262,048
Capital Expenditures Net of Capital-Carry(1)(2)	$	140,207	$	193,980	$	212,601
Total assets	$	2,093,465	$	1,825,638	$	2,323,572
Face value of long-term debt (current and long-term portions)(3)	$	583,425	$	614,070	$	563,310
Weighted average shares outstanding (basic)		521,316,320		514,151,731		500,136,092
Weighted average shares outstanding (diluted)		526,290,689		514,151,731		500,136,092

(1) Refer to the "Advisories and Other Guidance" section within this MD&A for additional information on Non-GAAP Financial Measures.
(2) 2017 capital expenditures exclude the cost of the Leismer Corner Acquisition.
(3) The face value of the 2022 Notes is US$450 million. The 2022 Notes were translated into Canadian dollars at the December 31, 2019 exchange rate of US$1.00 = C$1.2965.

ACCOUNTING POLICIES AND ESTIMATES

During the year ended December 31, 2019, there were no changes to Athabasca's accounting policies or use of estimates in the preparation of the consolidated financial statements and the notes thereto, except as noted below. A summary of the significant accounting policies used by Athabasca can be found in Note 3 of the December 31, 2019 audited consolidated financial statements. For the year ended December 31, 2019, Athabasca's significant estimates and judgment are as follows:

Significant Accounting Estimates and Judgments

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

The prepaid expenses and deposits include the financial assurance payment related to the firm service transportation agreement entered into during the third quarter of 2019. Judgment was applied in determining the current/non-current classification as in the event that the shipper agreements on the Keystone XL pipeline are terminated, the deposit would be considered a non-current asset rather than a current asset.

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

For purposes of impairment testing PP&E and E&E are aggregated into cash-generating units ("CGUs") based on separately identifiable and largely independent cash inflows. The determination of the Company's CGUs is subject to judgment. Factors considered in the classification of CGUs include the integration between assets, shared infrastructures, the existence of common sales points, geography, geologic structure and the manner in which management monitors and makes decisions regarding operations. CGUs are not larger than an operating segment. Impairment test calculations require the use of estimates and assumptions and are subject to change as new information becomes available. Factors that are subject to change include estimates of future commodity prices, expected production volumes, development timing, land values, quantity of reserves and resources, discount rates, recovery rates, timing of anticipated ramp-up of production, and future development, regulatory and operating costs. Changes in assumptions used in determining the recoverable amount could have a prospective material effect on the carrying value of the related PP&E and E&E CGUs.

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

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

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

The provision for the contingent payment obligation is based upon numerous assumptions including future WTI prices, inflation factors, foreign exchange rates and Leismer bitumen production. Actual cash outflows could differ from the estimates as a result of changes in any of the above noted assumptions.

The lease liability is based upon assumptions including the identification of fixed lease payments, separating lease components from non-lease components and the incremental borrowing rate.

The provision for income taxes is based on judgments in applying income tax law and estimates on the timing and likelihood of reversal of temporary differences between the accounting and tax bases of assets and liabilities. The provision for income taxes is based on Athabasca's interpretation of the tax legislation and regulations which are also subject to change. Athabasca recognizes a tax provision when a payment to tax authorities is considered more likely than not. Income tax filings are subject to audits and re-assessments and changes in facts, circumstances and interpretations of the standards which may result in a material increase or decrease in the Company's provision for income taxes. As at December 31, 2019 and as at December 31, 2018, Athabasca did not recognize deductible temporary differences in respect of income tax assets.

The Company utilizes commodity risk management contracts to manage its commodity price risk on its petroleum and natural gas sales. The Company may also utilize foreign exchange risk management contracts to reduce its exposure to foreign exchange risk associated with its interest payments on its US dollar denominated 2022 Notes. The calculated fair value of the risk management contracts relies on external observable market data including quoted forward commodity prices and foreign exchange rates. The resulting fair value estimates may not be indicative of the amounts actually realized at settlement and as such are subject to measurement uncertainty.

The measurement of stock-based compensation includes volatility, expected life and forfeiture rates which are based on management's assumptions and estimates.

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

Changes in accounting policies

IFRS 16 *Leases*

On January 1, 2019, Athabasca adopted the new IASB Lease Standard IFRS 16. IFRS 16 requires that former operating leases be capitalized and recognized on the consolidated balance sheet by the lessee. Lease assets and liabilities are initially measured at the present value of the unavoidable lease payments and amortized over the lease term. Lessor accounting remains consistent with current IFRS standards. Athabasca adopted IFRS 16 using a modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information and recognizes the cumulative effect of IFRS 16 prior to January

1, 2019 as an adjustment to the opening accumulated deficit and applies the standard prospectively. On adoption, Athabasca also elected to apply the following expedients as permitted under the standard:

- Leases with terms ending within 12 months are recognized as short-term leases.
- Short-term leases and leases of low value assets that have been identified are not recognized on the consolidated balance sheet. Expenses for these leases are recognized as incurred with the amounts disclosed in the notes to the consolidated financial statements.
- The provision for onerous leases previously recognized was applied to the value of the associated right-of-use asset ("Leased asset"). In this case, no impairment assessment was performed under IAS 36 *Impairment.*

Upon adoption, Athabasca recognized a Leased asset of $12.6 million within PP&E and a lease liability of $18.7 million within provisions and other liabilities relating to its head office lease. The liability was measured at the present value of the remaining lease payments using an incremental borrowing rate of 10.0%. Athabasca netted the previously recognized onerous office lease provision of $3.1 million against the associated Leased asset on January 1, 2019. An adjustment to the opening accumulated deficit of $3.0 million was recognized as a result of using the modified retrospective approach.

During the year ended December 31, 2019, interest expense increased by $1.7 million, depreciation increased by $2.1 million and general and administrative expense decreased by $2.8 million as a result of the adoption of IFRS 16. For the year ended December 31, 2019, cash flows associated with the lease repayments of $4.0 million were allocated between operating and financing activities in the amounts of $1.7 million and $2.3 million, respectively, based on their interest and principal repayment components.

As a result of the adoption of IFRS 16, the Company has revised its accounting policy for leases as follows:

A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. A lease obligation and corresponding Leased asset are recognized at the commencement of the lease. Lease liabilities are initially measured at the present value of the unavoidable lease payments and discounted using the Company's incremental borrowing rate when an implicit rate in the lease is not readily available. Interest expense is recognized on the lease obligations using the effective interest rate method. The Leased asset is recognized at the amount of the lease liability, adjusted for lease incentives received and initial direct costs, on commencement of the lease. The Leased asset is depreciated on a straight-line basis over the lease term. The Company is required to make judgments and assumptions on incremental borrowing rates and lease terms. The carrying balance of the Leased assets and lease liabilities, and related interest and depreciation expense, may differ due to changes in market conditions and expected lease terms.

Recent Accounting Pronouncements

The IASB issued International Financial Reporting Interpretations Committee (“IFRIC”) 23 *Uncertainty over Income Tax Treatments* in June 2017. IFRIC 23 is effective beginning January 1, 2019 and applies to the determination of the accounting tax position when there is uncertainty over income tax treatments under IAS 12 *Income Taxes*. Management has assessed the requirements of IFRIC 23 and concluded that the adoption of this interpretation does not have a material impact on the consolidated financial statements.

ADVISORIES AND OTHER GUIDANCE

Non-GAAP Financial Measures

The "Adjusted Funds Flow", "Light Oil Operating Income (Loss)", "Light Oil Operating Netback", "Light Oil Capital Expenditures Net of Capital-Carry", "Thermal Oil Operating Income (Loss)", "Thermal Oil Operating Netback", "Consolidated Operating Income (Loss)", "Consolidated Operating Netback", "Consolidated Capital Expenditures Net of Capital-Carry" and "Consolidated Free Cash Flow" financial measures contained in this MD&A do not have standardized meanings which are prescribed by IFRS and they are considered to be non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers and should not be considered in isolation with measures that are prepared in accordance with IFRS.

The following table reconciles cash flow from operating activities in the consolidated financial statements for the three months and year ended December 31, 2019 and 2018 to Adjusted Funds Flow:

($ Thousands)	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
Cash flow from operating activities[1]	$ 32,975	$ (2,253)	$ 92,632	$ 83,844
Restructuring	—	3,604	—	3,604
Changes in non-cash working capital	(11,886)	(81,506)	58,453	(103,787)
Settlement of provisions	389	4,859	3,675	9,937
Long-term deposits	—	—	—	12,577
ADJUSTED FUNDS FLOW[1]	$ 21,478	$ (75,296)	$ 154,760	$ 6,175

(1) For the three months and year ended December 31, 2019, the adoption of IFRS 16 *Leases* resulted in a $0.6 million and $2.3 million increase in cash flow from operating activities and Adjusted Funds Flow, respectively.

Adjusted Funds Flow is not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS. The Adjusted Funds Flow measure allows management and others to evaluate the Company's ability to fund its capital programs and meet its ongoing financial obligations using cash flow internally generated from ongoing operating related activities. Adjusted Funds Flow per share is calculated as Adjusted Funds Flow divided by the applicable number of weighted average shares outstanding.

The Light Oil Operating Income (Loss) measure in this MD&A is calculated by subtracting royalties, operating expenses and transportation & marketing expenses from petroleum and natural gas sales. The Light Oil Operating Netback measure is calculated by dividing the Light Oil Operating Income (Loss) by the Light Oil production and is presented on a per boe basis. The Light Oil Operating Income (Loss) and the Light Oil Operating Netback measures allow management and others to evaluate the production results from the Company's Light Oil assets. The table on page 9 reconciles Light Oil Operating Income (Loss) to *Note 19 - Segmented Information* in the consolidated financial statements for the three months and year ended December 31, 2019.

The Operating Income (Loss) measure in this MD&A with respect to the Leismer Project and Hangingstone Project is calculated by subtracting the cost of diluent blending, royalties, operating expenses and transportation & marketing expenses from blended bitumen sales. The Thermal Oil Operating Netback measure is calculated by dividing the respective projects Operating Income (Loss) by its respective bitumen sales volumes and is presented on a per barrel basis. The Thermal Oil Operating Income (Loss) and the Thermal Oil Operating Netback measures allow management and others to evaluate the production results from the Company's Thermal Oil assets. The table on page 13 reconciles Thermal Oil Operating Income (Loss) to *Note 19 - Segmented Information* in the consolidated financial statements for the three months and year ended December 31, 2019.

The Consolidated Operating Income (Loss) measure in this MD&A is calculated by adding or subtracting realized gains (losses) on commodity risk management contracts, royalties, the cost of diluent blending, operating expenses and transportation & marketing expenses from petroleum and natural gas sales. The Consolidated Operating Netback measure is calculated by dividing Consolidated Operating Income (Loss) by the total sales volumes and is presented on a per boe basis. The Consolidated Operating Income (Loss) and the Consolidated Operating Netback measures allow management and others to evaluate the production results from the Company's Light Oil and Thermal Oil assets combined together including the impact of realized commodity risk management gains or losses. The table on page 6 reconciles Consolidated Operating Income (Loss) to *Note 19 – Segmented Information* in the consolidated financial statements for the three months and year ended December 31, 2019.

The Consolidated Capital Expenditures Net of Capital-Carry and Light Oil Capital Expenditures Net of Capital-Carry measures in this MD&A are calculated in the tables on pages 7 and 9. These measures allow management and others to evaluate the true net cash outflow related to Athabasca's capital expenditures.

The Consolidated Free Cash Flow measure in this MD&A is calculated by subtracting Capital Expenditures Net of Capital-Carry of $140.2 million from Adjusted Funds Flow of $154.8 million. This measure allows management and others to evaluate Athabasca's ability to generate funds to finance operations and capital expenditures.

Comparative Figures

Certain comparative figures have been restated to conform to the current period presentation.

Disclosure Control and Procedures

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

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

For the year ended December 31, 2019, 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 Controls 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, 2019, based on the Internal Control - Integrated Framework (the "Framework") established by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In making its assessment, Management used the COSO 2013 Framework in order to evaluate the design and effectiveness of internal control over financial reporting. Based upon management's assessment, the Company has maintained effective internal control over financial reporting as of December 31, 2019.

Risk Factors

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

Operational risks

- the performance of the Company's assets;
- Athabasca's exploration and development budget and Athabasca's capital expenditure programs;
- failure to realize anticipated benefits of acquisitions or divestments;
- uncertainties inherent in estimating quantities of Proved Reserves, Probable Reserves and Contingent Resources;
- the timing of certain of Athabasca's operations and projects, including the commencement of its planned Thermal Oil Division development projects, the exploration and development of Athabasca's Light Oil assets and the levels and timing of anticipated production;
- dependence upon Murphy as a working interest participant in its Light Oil assets and as operator of the Greater Kaybob assets;
- risks and uncertainties inherent in Athabasca's operations, including those related to exploration, development and production of bitumen, crude oil, natural gas and natural gas liquids reserves and resources;
- risks related to gathering and processing facilities and pipeline systems;
- reliance on third party infrastructure;
- seasonality and weather conditions, which may be impacted by climate change;
- risks associated with events of force majeure; and
- expiration of leases and permits or the failure of Athabasca or the holder of certain licenses, leases or permits to meet specific requirements of such licenses, leases or permits.

Planning risks

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

Financial and market risks

- general economic, market and business conditions in Canada, the United States and globally;
- future market prices for crude oil, natural gas, condensate and bitumen blend;
- Canadian heavy and light oil export capacity constraints and the resulting impact on realized pricing;
- Athabasca's projections of commodity prices, costs and netbacks;
- the substantial capital requirements of Athabasca's projects and the Company's ability to raise capital;
- risk of reduced capital availability due to environmental and climate related reputational issues for industry;
- the potential for future joint venture arrangements;
- insurance risks;
- hedging risks;
- variations in foreign exchange and interest rates;
- risks related to the Credit Facility, the Letter of Credit Facility, the Unsecured Letter of Credit Facility and the 2022 Notes;
- risks related to the Common Shares;
- risks of cybersecurity threats including the possibility of potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of our information technology systems; and
- potential economic disruption that may result from the spread of COVID-19 (coronavirus).

Legal and compliance risks

- the regulatory framework governing royalties, taxes, environmental matters and foreign investment in the jurisdictions in which Athabasca conducts and will conduct its business;
- risks related to Athabasca's filings with taxation authorities, including the risk of tax related reviews and reassessments;
- actions taken by the American administration on the imposition of taxes on the importation of goods into the United States;
- aboriginal claims;
- risks associated with establishing and maintaining systems of internal controls; and
- inaccuracy of forward-looking information.

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

Forward Looking Information

This MD&A contains forward-looking information that involves various risks, uncertainties and other factors. All information other than statements of historical fact is forward-looking information. The use of any of the words “anticipate,” “plan,” “continue”, “estimate”, “expect”, “may”, “will”, “project”, “target”, “should”, “believe”, “predict”, “pursue” and “potential” and similar expressions are intended to identify forward-looking information. The forward-looking information is not historical fact, but rather is based on the Company’s current plans, objectives, goals, strategies, estimates, assumptions and projections about the Company’s industry, business and future financial results. This information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. No assurance can be given that these expectations will prove to be correct and such forward-looking information included in this MD&A should not be unduly relied upon. This information speaks only as of the date of this MD&A. In particular, this MD&A may contain forward-looking information pertaining to the following: the Company's future growth outlook and how that growth outlook is funded; estimates of corporate, Thermal Oil and Light Oil production levels; reserve life index; expectation related to water disposal well at Leismer; expectation of results of CRA audits and reassessments; the Company's anticipated sources of funding for 2020 and beyond; the Company's estimated future minimum commitments; the future allocation of capital; and other matters.

In addition, information and statements in this MD&A relating to “Reserves” and “Resources” are deemed to be forward-looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and that the reserves and resources described can be profitably produced in the future. Certain assumptions related to the Company’s Reserves and Resources are contained in the report of McDaniel & Associates Consultants Ltd. ("McDaniel") evaluating Athabasca’s Proved Reserves, Probable Reserves and Contingent Resources as at December 31, 2019 (which is respectively referred to herein as the "McDaniel Report”).

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

Actual results could differ materially from those anticipated in this forward-looking information as a result of the risk factors set forth in the Company’s most recent AIF available on SEDAR at www.sedar.com, including, but not limited to: weakness in the oil and gas industry; exploration, development and production risks; prices, markets and marketing; market conditions; climate change and carbon pricing risk; regulatory environment and changes in applicable law; gathering and processing facilities, pipeline systems and rail; statutes and regulations regarding the environment; political uncertainty; anticipated benefits of acquisitions and dispositions; ability to finance capital requirements; state of the capital markets; abandonment and reclamation costs; changing demand for oil and natural gas products; royalty regimes; foreign exchange rates and interest rates; reserves; hedging; operational dependence; operating costs; project risks; financial assurances; diluent supply; third party credit risk; aboriginal claims; reliance on key personnel and operators; income tax; cybersecurity; advanced technologies; hydraulic fracturing; liability management; seasonality and weather conditions; unexpected events; internal controls; insurance; litigation; natural gas overlying bitumen resources; competition; chain of title and expiration of licenses and leases; breaches of confidentiality; new industry related activities or new geographical areas; and risks related to our debt and securities.

The risks and uncertainties referred to above are described in more detail in Athabasca’s most recent AIF, which is available on the Company’s SEDAR profile at www.sedar.com. Readers are cautioned that the foregoing list of risk factors should not be construed as exhaustive. The forward-looking information included in this MD&A is expressly qualified by this cautionary statement and is made as of the date of this MD&A. The Company does not undertake any obligation to publicly update or revise any forward-looking information except as required by applicable securities laws.

The Company’s financial condition and results of operations discussed in this MD&A will not necessarily be indicative of the Company’s future performance, particularly considering that many of the Company’s activities are currently in the early stages of their planned exploration and/or development.

Reserves and Resource Information

The McDaniel Report was prepared using the assumptions and methodology guidelines outlined in the COGE Handbook and in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities,* effective December 31, 2019. There are numerous uncertainties inherent in estimating quantities of bitumen, crude oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth above are estimates only. In general, estimates of economically recoverable reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially. For those reasons, estimates of the economically recoverable reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. There is no certainty that it will be commercially viable to produce any portion of the resources. Reserves figures described herein have been rounded to the nearest MMbbl or MMboe. Contingent Resources described herein have been rounded to the nearest billion barrels. For additional information regarding the consolidated reserves and resources of the Company as evaluated by McDaniel in the McDaniel Report, please refer to the Company’s AIF that is available on SEDAR at www.sedar.com.

Oil and Gas Information

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

Drilling Locations

The 700 Duvernay drilling locations referenced on page 7 of this MD&A include: 45 proved undeveloped or non-producing locations and 40 probable undeveloped locations for a total of 85 booked locations with the balance being unbooked locations. The 200 Montney drilling locations referenced on page 7 of this MD&A include: 77 proved undeveloped locations and 24 probable undeveloped locations for a total of 101 booked locations with the balance being unbooked locations. Proved undeveloped locations and probable undeveloped locations are booked and derived from the Company's most recent independent reserves evaluation as prepared by McDaniel as of December 31, 2019 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, additional reservoir information that is obtained and other factors.

Definitions

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

“**Contingent Resources**” are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include such factors as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as “Contingent Resources” the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources may be divided into the following project maturity sub-classes: “Development Pending” is assigned to Contingent Resources for a particular project where resolution of the final conditions for development is being actively pursued (high chance of development); “Development On Hold” is assigned to Contingent Resources for a particular project where there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator; “Development Unclarified” is assigned to Contingent Resources for a particular project where evaluation is incomplete and there is ongoing activity to resolve any risks or uncertainties or which require significant further appraisal to clarify potential for development and where contingencies have yet to be defined; “Development Not Viable” is assigned to Contingent Resources for a particular project where no further data acquisition or evaluation is currently planned and there is a low chance of development. As at December 31, 2019, the Company reported Contingent Resources on a risked and unrisked basis located in its Leismer and Corner asset areas in the Development Pending project maturity sub-class and for the Dover West Sands asset area in the Development on Hold project maturity sub-class.

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

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

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

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

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

Abbreviations

AECO	physical storage and trading hub for natural gas on the TC Alberta transmission system which is the delivery point for various benchmark Alberta index prices.
bbl	barrel
bbl/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
C$	Canadian Dollars
COGE	Canadian Oil and Gas Evaluation
GAAP	Generally Accepted Accounting Principles
LIBOR	London interbank offered rate
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMbbl	millions of barrels
MMboe	millions of barrels of oil equivalent
MMBtu	million British thermal units
SAGD	steam assisted gravity drainage
US$	United States Dollars
WTI	West Texas Intermediate
WCS	Western Canadian Select