ATHABASCA OIL CORPORATION

FOR IMMEDIATE RELEASE
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Athabasca Oil Corporation Announces 2017 First Quarter Results

CALGARY – Athabasca Oil Corporation (TSX: ATH) ("Athabasca" or the "Company") is pleased to provide its 2017 first quarter results and an operations update. The first quarter marks the completion and integration of the transformational Statoil oil sands acquisition, a successful balance sheet refinancing and operational momentum in the Light Oil division. The Company is positioned for strong economic growth through the second half of 2017.

First Quarter and Recent Highlights

- **Q1 2017 highlights**
  - Production of 26,737 boe/d (95% liquids), representing 72% per share growth year over year
  - Capital expenditures of $78 million ($67 million net Light Oil and $11 million Thermal Oil)
  - Cost discipline drives a 54% year over year G&A reduction to $2.67/boe
- **Successful Placid Montney winter program (70% working interest)**
  - Current Light Oil production is approximately 7,500 boe/d, representing 120% growth over Q1 2017
  - 20 wells rig released with 11 wells completed and placed on production before break-up
  - Initial production and pressure data from the new wells are supporting Athabasca's type curve which is highly economic in the current pricing environment (52% IRR & 22 month payback at US$50/bbl WTI). Initial free liquids yields are trending between 300 – 500 bbl/mmcf
  - Commissioned the Placid battery and infrastructure project in April with capacity for 10,000 bbl/d and 36 mmcf/d
  - Positioned for strong economic production and cash flow growth through H2 2017
- **$200 million gross Duvernay joint venture program in 2017 (30% working interest)**
  - Murphy operated two rigs through the winter and rig released eight horizontal wells
  - Completions operations underway on two pads with ten additional spuds planned for H2 2017
  - Advancing phase window delineation and optimized well design with longer laterals and larger fracs (up to 3,000 meters and 3,000 lbs/ft)
- **Thermal division underpins low corporate decline and free cash flow generation**
  - Successful integration of Leismer drives $11 million of free cash flow through February and March
  - $30 million capital reduction in 2017 as a result of continued strong well pair performance and the prior investment in sustaining infill wells
  - Commodity hedging of 13,000 bbl/d at ~$53/bbl WCS protects near-term cash flow
- **Solidified the balance sheet and long-term funding position**
  - Strong liquidity and financial flexibility with $327 million of cash, a $203 million capital carry balance and $103 million of available credit facilities at quarter end

- Term debt extended to 2022 through the issuance of US$450 million of new covenant light notes
- Significant asset value in operated Thermal and Light Oil infrastructure

Athabasca's Strategy

Athabasca is an intermediate oil weighted producer with exposure to several of the largest resource plays in Western Canada including the Montney, Duvernay and oil sands. The Company has a fully funded development outlook capable of delivering growth to 60,000 boe/d by 2020 (40% production per share CAGR) and is guided by a strategy that includes:

- **Light Oil: Defined and Material Growth**
  - A scalable operated Montney position at Placid
  - Funded Duvernay development through the joint venture with Murphy Oil
  - Production growth to over 10,000 boe/d by year-end 2017 and approximately 25,000 boe/d over the next five years
- **Thermal Oil: Free Cash Flow with Leverage to Oil prices**
  - A large low decline asset base accelerates free cash flow
  - Free cash flow of approximately $350 million over a five year period at US$55/bbl WTI
  - Future low risk expansion options
- **Financial Sustainability**
  - Maturing cash flow profile with strong sustainability metrics and a low overall corporate production decline of approximately 7.5% annually
  - Diverse asset base provides flexibility in future capital allocation decisions
  - Net debt to cash flow expected to be less than 2.5x at year-end 2018 (US$55/bbl WTI)

Financial and Operating Highlights

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

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

1) Refer to "Advisories and Other Guidance" in the MD&A for additional information on Non-GAAP Financial Measures.
2) The Leismer Project was acquired on January 31, 2017. From the date of the acquisition to the end of the first quarter of 2017, the Leismer Project produced 22,521 bbl/d.
3) Thermal Oil capital expenditures excludes the cost of the Leismer Corner Acquisition.
4) Consists of cash of $431.3 million, common shares of $166.0 million and contingent payment obligations of $24.7 million.

Operations Update

Light Oil

Greater Placid Montney (Athabasca operated, 70% working interest)

At Placid, Athabasca completed an active winter program that included rig releasing 20 Montney wells, the commissioning of a new battery and the tie-in of three multi-well pads. Placid is positioned for flexible and scalable economic growth over the next five years.

Two drilling rigs commenced operations last fall and the Company rig released a total of 20 horizontal wells from five pads. The program was designed to accelerate pad drilling operations targeting two Montney cycles. Drilling costs averaged $3.0 million per well with average lateral lengths of approximately 2,600 meters and the latest eight wells up to 3,000 meters. The Company maintained its drilling costs year over year as operational efficiencies offset modest service cost inflation. Drilling performance on the latest wells were industry pacesetters reaching total depth in approximately 15 days. The Company is advancing operational readiness for next winter's drilling program which will include a combination of low risk infill locations off existing pads and step-outs from the core development.

A total of three pads, 11 wells, were completed this winter with all wells placed on production in April through the Company's owned and operated infrastructure (surface locations 7-30, 16-30 & 12-19-60-23W5). The Company modified its completion design to a plug and perf from ball drop with the goal to improve fracture intensity and ultimately long term rates and recoveries. Completion costs for the program averaged $4.2 million per well ($124,000 per stage, 34 average stages per well) with proppant intensity up to 1,000 lbs/ft (1.8 T/m). The remaining two pads are expected to be completed following break-up and placed on production in the third quarter (surface locations 3-4-61-23W5 & 7-33-60-23W5).

The Placid battery and infrastructure project was commissioned in April. The new infrastructure will support Athabasca's mid-term growth targets and has capacity of 10,000 bbl/d and 36 mmcf/d (gross). The Company operates all of its regional infrastructure with liquids pipe connected to the Pembina Peace system and gas processed through Keyera's Simonette Gas Plant and marketed through the Alliance System.

In April, Athabasca's Light Oil production was impacted by a 16 day unplanned shutdown of the Keyera Simonette Gas Plant. The Company was able to partially mitigate the impact by redirecting a portion of its regional Kaybob and Placid production to the SemCAMS KA plant. During the shutdown approximately 50% of volumes were restricted with an estimated 250 boe/d impact to annual volumes.

Current Light Oil production is approximately 7,500 boe/d representing 120% growth over Q1 2017. In the Montney, initial production and pressure data from the new wells are supporting Athabasca's type curve which is highly economic in the current pricing environment (52% IRR and 22 month payback at US$50/bbl WTI). Regional production is temporarily restricted as a result of spring road bans limiting the trucking of flowback fluid. Initial free liquids yields have ranged between 300 – 500 bbl/mmcf and compare favorably to type curve expectations between 200 – 300 bbl/mmcf during the first 30 days of operation. The

Company anticipates increasing gas rates over time as the wells clean-up. Extended production rates for the new wells will be provided with the Company's Q2 2017 results.

Decisions regarding second half activity levels will be finalized in the summer and the Company retains flexibility to adapt the program to results and external market conditions.

Greater Kaybob Duvernay (Murphy operated, 30% working interest)

Joint venture operations commenced in the fall of 2016 with the objective of driving near-term production and cash flow growth, delineation across all phase windows, optimizing well design and maximizing land retention.

Murphy operated two drilling rigs through the winter season and rig released eight wells from four pads. Initial activity has been focused in the condensate rich gas window at Kaybob West and in the volatile oil window at Kaybob West North. Drilling performance has been competitive with industry peers and wells have averaged approximately 24 days spud to rig release (5,000 – 6,000 meters average measured depth). Activity through the second half will step out through the volatile oil window at Kaybob East, Two Creeks and Simonette.

A two well pad at surface location 1-18-64-20W5 was spud in late 2016 and completed and placed on production through the first quarter. Utilizing an existing pad, Murphy drilled two offsets to the 1-7-64-20W5 well with average lateral lengths of approximately 1,400 meters. A restricted flow back technique was employed to evaluate completion design and reservoir production characteristics over time.

A two well pad at surface location 4-32-64-20W5 was rig released in early March with average laterals of approximately 2,800 meters. Completions operations are underway with tie-in expected post break-up.

A single well at surface location 16-18-65-20W5 was rig released in late March with a 2,900 meter lateral. This well is the longest lateral drilled to date and the most northern well in the volatile oil window. Completions operations are planned post break-up.

A three well pad at surface location 11-18-64-20W5 was rig released in April with average laterals of approximately 2,400 meters. Completions operations are underway with tie-in expected post break-up.

The 2017 budget includes spudding 16 gross wells which are a mix of pad development locations and delineation wells throughout the volatile oil window. Murphy intends to optimize well design with average lateral lengths increasing to between 2,500 – 3,000 meters and frac intensity between 2,000 – 3,000 lbs/ft (3 – 5 T/m). Total lateral drilling for the program is approximately 45,000 meters and this compares to Athabasca's initial 20 well appraisal campaign of approximately 27,000 meters since 2012.

Results from the Duvernay program are expected to pick up through H2 2017 as wells are completed and tied-in post break-up with 10 additional spuds planned for the balance of the year.

Thermal Oil

Leismer

Athabasca assumed operatorship of Leismer following closing of its acquisition on January 31, 2017. The asset is meeting expectations with an established low decline production base and averaged 22,521 bbl/d through February and March. Over the same period the asset generated $17 million of operating income and $11 million of free cash flow. Leismer is a Tier 1 thermal asset with a strong free cash flow profile in the current price outlook.

As a result of strong well pair performance and prior investment in sustaining infill wells the 2017 capital budget at Leismer has been reduced by $30 million to $54 million (previously $84 million) with no impact to planned production. Athabasca also sees opportunities for operating cost reductions over the next year including alternate diluent sourcing which is expected to be operational in mid-2018.

Near-term operations will focus on production optimization across the field and the start-up of predrilled infills on Pad L5. Through the mid-term the Company intends to expand Pad L2 with five new well pairs and evaluate infill opportunities on Pads L3 and L4.

Hangingstone

Hangingstone averaged 8,552 bbl/d for the quarter and approximately 9,200 bbl/d for March. As previously guided the Company is anticipating facility maintenance in April and May that will impact near-term production growth. The project is expected to reach name plate capacity of approximately 12,000 bbl/d in 2018 with minimal maintenance capital expected within the first five years of operations.

Egress Update

In the first quarter Athabasca secured 20,000 bbl/d of blended bitumen capacity on the Kinder Morgan Trans Mountain Expansion Project. The pipeline project is federally approved and is expected to be in-service in late 2019. The Company believes securing term take-away capacity to multiple end markets is essential to its long-term strategy. The Trans Mountain pipeline will provide Athabasca exposure to global oil demand growth.

2017 Outlook and Budget

Light Oil Guidance

Athabasca's 2017 Light Oil capital budget is unchanged at $135 million ($120 million for Placid Montney and $15 million net post capital carry for Duvernay) with production guidance of 6,500 – 7,500 boe/d and production expected to reach 10,000 boe/d before year-end. H2 2017 Montney capital will be assessed mid-year.

Thermal Oil Guidance

Athabasca's 2017 Thermal Oil budget has been reduced by $30 million to $75 million (approximately a 30% reduction) with unchanged production guidance of 29,000 – 32,500 bbl/d. The capital program now consists of $54 million at Leismer, $15 million at Hangingstone and an additional $6 million for maintaining Athabasca's long dated thermal leases.

2017 Budget & Guidance Details

	Full Year
CORPORATE (net)	
Production[1] (boe/d)	36,000 – 40,000
Liquids Weighting (%)	~90%
Funds Flow from Operations ($MM)	~$90
LIGHT OIL	
Production (boe/d)	6,500 – 7,500
Operating Income ($MM)	~$75
Capital Expenditures ($MM)	$135
THERMAL OIL	
Bitumen Production[1] (bbl/d)	29,000 – 32,500
Operating Income ($MM)	~$100
Capital Expenditures ($MM)	$75
COMMODITY ASSUMPTIONS	
WTI (US$/bbl)	$52.00
Edmonton Par (C$/bbl)	$65.00
Western Canadian Select (C$/bbl)	$50.00
AECO Gas (C$/mcf)	$2.75
FX (US$/C$)	0.75

Notes:
1) Production guidance reflects a January 31, 2017 closing date for the Statoil acquisition with Leismer volumes to be reported from February – December.

Balance Sheet and Risk Management Update

In the first quarter Athabasca completed a comprehensive balance sheet refinancing transaction. This included the issuance of US$450 million of five-year covenant lite second lien notes to replace the Company's existing $550 million of second lien notes, and the establishment of a $120 million reserve based credit facility. Athabasca is well positioned to advance its strategic objectives with multi-year funding certainty, financial flexibility and a strong liquidity outlook.

At the end of the first quarter Athabasca had a cash positon of $327 million (inclusive of restricted cash) and $103 million of available credit facilities. The Company also has $203 million of remaining capital carry that will drive $1 billion of gross Duvernay investment over four years, as well as significant asset value in its established and operated Thermal and Light Oil infrastructure.

Athabasca anticipates an internally funded capital program in 2018 at US$55/bbl WTI with net debt to cash flow of less than 2.5x and trending lower in subsequent years.

The Company has recently commenced a commodity risk management program designed to protect a base level of cash flow and support its capital plans. The Company intends to hedge a minimum of 20,000 bbl/d for the balance of 2017 with 13,000 bbl/d of Western Canadian Select ("WCS") hedged at approximately C$53/bbl and an additional 7,000 bbl/d of WCS differential hedged at approximately US$14.75/bbl. Going forward, a multi-year hedging program is expected to form a part of the Company's risk management strategy.

About Athabasca Oil Corporation

Athabasca Oil Corporation is a Canadian energy company with a focused strategy on the development of thermal and light oil assets. Situated in Alberta's Western Canadian Sedimentary Basin, the Company has amassed a significant land base of extensive, high quality resources. Athabasca's common shares trade on the TSX under the symbol "ATH". For more information, visit www.atha.com.

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Reader Advisory:

This News Release 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”, “believe”, “contemplate”, “target”, “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 operating and 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 News Release should not be unduly relied upon. This information speaks only as of the date of this News Release. In particular, this News Release contains forward-looking information pertaining to, but not limited to, the following: the Company's five-year growth outlook and that such growth outlook is fully funded; the Company’s expectation of realizing strong economic growth through the second half of 2017; estimates of, and timing of, sustainable free cash flow generation, net debt to cash flow levels and cash and cash equivalents and liquidity, for certain future periods; the Company’s 2017 production guidance corporately as well as for each of its Light Oil and Thermal Oil projects; the Company’s expected production and economic growth in 2017 and over the next five years; the Company’s production levels by 2020; that the Placid area assets will provide flexible and scalable economic growth over the next five years; the payback timelines expected for the Company’s Montney wells; the Company’s plans with respect to its 2017/2018 winter drilling program; the Company’s expectation that it will increase gas rates with well clean-up; the benefits expected to be realized from the Company’s modified well completion design; the benefits expected to be realized from the Company’s new Placid battery and infrastructure; the second half 2017 program for the Company’s interest in the Murphy-operated assets; the expectation that the Trans Mountain pipeline will be in service by late 2019; the impact of, and the benefits expected to be realized from, the Statoil transaction; and future performance and characteristics of the Leismer and Corner assets including their quality and resilience to lower commodity prices; the Company’s expectation that its low decline thermal oil asset base will accelerate its free cash flow generation; the Company’s expectation that it will be able to maintain stable production from the Leismer assets for the foreseeable future; the Company’s expectation that its Thermal Oil assets provide future low risk expansion options; the Company’s Leismer production optimization plans; the Company’s ability to reduce operating and capital costs over the next five years; the timing for achievement of name plate capacity at Hangingstone and expectations regarding maintenance capital within the first five years of operations; future drilling and completion plans including the number of wells expected to be drilled and timing of spudding, rig-releasing and completing such wells; the timing of when such wells will be placed on production; the total number of lateral meters expected to be drilled in 2017; expectations with respect to future production hedging levels and the benefit expected to be realized from such hedging; decline rates; estimates of 2017 funds flow from operations, operating income and capital expenditures; the capability of the Company's five-year development outlook to deliver potential growth in per share production; the benefits expected to be realized by the Company from its issuance of the US$450 million senior secured second lien notes and establishment of the $120 million credit facility; and other matters.

Information relating to "reserves" is also deemed to be forward-looking information, as it involves the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future. With respect to forward-looking information contained in this News Release, assumptions have been made regarding, among other things: commodity prices for petroleum and natural gas; the regulatory framework governing royalties, taxes and environmental matters in the jurisdictions in which the Company conducts and will conduct its 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, the Company’s ability to accelerate development when prices recover; Athabasca’s cash-flow break-even commodity price; geological and engineering estimates in respect of Athabasca’s reserves and resources; the applicability of technologies for the recovery and production of the Company’s reserves and resources; the Company’s ability to demonstrate the quality of its asset base and to build large-scale projects; 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; the Company’s ability to obtain equipment in a timely and cost-efficient manner; the geography of the areas in which the Company is conducting exploration and development activities; that Athabasca and its security holders will obtain the anticipated benefits from the $US450 senior secured second lien note and the $120 million credit facility and the Company’s ability to obtain equipment in a timely and cost-efficient manner.

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 Annual Information Form (“AIF”) dated March 9, 2017 that is or will be available on SEDAR at www.sedar.com, including, but not limited to: fluctuations in market prices for crude oil, natural gas and bitumen blend; political and general economic, market and business conditions in Alberta, Canada, the United States and globally; changes to royalty regimes, environmental risks and hazards; alternatives to and changing demand for petroleum products; the potential for management estimates and assumptions to be inaccurate; dependence on Murphy as the Company’s joint venture participant in the Company’s Duvernay and Montney assets; the dependence on Murphy as the operator of the Company’s Duvernay assets; the substantial capital requirements of Athabasca’s projects and the ability to obtain financing for Athabasca’s capital requirements; operational and business interruption risks associated with the Company’s facilities; failure by counterparties to make payments or perform their operational or other obligations to Athabasca in compliance with the terms of contractual arrangements between Athabasca and such counterparties, and the possible consequences thereof; long term reliance on third parties; aboriginal claims; failure to obtain regulatory approvals or maintain compliance with regulatory requirements; failure to meet development schedules and potential cost overruns; variations in foreign exchange and interest rates; factors affecting potential profitability; risks related to future acquisition and joint venture activities; reliance on, competition for, loss of, and failure to attract key personnel; uncertainties inherent in estimating quantities of reserves and resources; changes to Athabasca’s status given the current stage of development; litigation risk; risks and uncertainties inherent in SAGD and other bitumen recovery processes; risks related to hydraulic fracturing, including those related to induced seismicity; expiration of leases and permits; risks inherent in Athabasca’s operations, including those related to exploration, development and production of petroleum, natural gas and oil sands reserves and resources; risks related to gathering and processing facilities and pipeline systems; availability of drilling and related equipment and limitations on access to Athabasca’s assets; increases in costs could make Athabasca’s projects uneconomic; the effect of diluent and natural gas supply constraints and increases in the costs thereof; environmental risks and hazards; failure to accurately estimate abandonment and reclamation costs; reliance on third party infrastructure; seasonality; hedging risks; risks associated with maintaining systems of internal controls; insurance risks; claims made in respect of Athabasca’s operations, properties or assets; competition for, among other things, capital, export pipeline capacity and skilled personnel; the failure of Athabasca or the holder of certain licenses, leases or permits to meet specific requirements of such licenses, leases or permits; risks related to Athabasca’s amended credit facilities and senior secured notes; and risks related to Athabasca’s common shares.

Also included in this press release are estimates of Athabasca's 2017 capital expenditures, funds flow from operations, operating netbacks and operating income levels, which are based on the various assumptions as to production levels, commodity prices and currency exchange rates and other assumptions disclosed in this news release. To the extent any such estimate constitutes a financial outlook, it was approved by management and the Board of Directors of Athabasca on May 3, 2017, and is included to provide readers with an understanding of the funding of Athabasca's capital expenditure program in 2017 and an outlook for the Company's activities and results and readers are cautioned that the information may not be appropriate for other purposes. Management does not have firm commitments for all of the costs, expenditures, prices or other financial assumptions used to prepare the financial outlook or assurance that such operating results will be achieved and, accordingly, the complete financial effects of all of those costs, expenditures, prices and operating results are not objectively determinable. The actual results of operations of the Company and the resulting financial results may vary from the amounts set forth herein, and such variations may be material. The financial outlook contained in this New Release was made as of the date of this press release and the Company disclaims any intention or obligations to update or revise such financial outlook, whether as a result of new information, future events or otherwise, unless required pursuant to applicable law.

Oil and Gas Information

“BOEs" 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.

Initial Production Rates

The initial production rates provided in this News Release should be considered to be preliminary. Initial production rates disclosed herein may not necessarily be indicative of long term performance or of ultimate recovery.

Non-GAAP Financial Measures

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

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

The Light Oil Operating Income and Light Oil Operating Netback measures in this MD&A are calculated by subtracting royalties and operating and transportation expenses from petroleum and natural gas sales and midstream revenues received. The Light Oil Operating Netback measure is presented on a per boe basis. The Light Oil Operating Income and the Light Oil Operating Netback measures allow management and others to evaluate the production results from the Company’s Light Oil assets.

The Operating Income and Operating Netback measures in this MD&A with respect to the Leismer Project and Hangingstone Project are calculated by subtracting the cost of diluent blending, royalties, operating expenses and transportation expenses from blended bitumen sales. The consolidated Thermal Oil Operating Income and Operating Netback measures also include realized gains on commodity risk management contracts. The Thermal Oil Operating Netback measure is presented on a per bbl basis. The Thermal Oil Operating Income and the Thermal Oil Operating Netback measures allow management and others to evaluate the production results from the Company’s Thermal Oil assets.

The Net Debt measure is calculated by summing the face value of outstanding term debt with current liabilities and subtracting current assets adjusted for the capital carry receivable and risk management contracts. The Net Debt measure is not intended to represent other measures of financial position on the Company’s balance sheet that are calculated in accordance with IFRS. The Net Debt financial measure allows management and others to evaluate the Company’s funding position and utilization of debt within its capital structure.