FOR IMMEDIATE RELEASE
July 26, 2023

# Athabasca Oil Announces 2023 Second Quarter Results

CALGARY – Athabasca Oil Corporation (TSX: ATH) ("Athabasca" or the "Company") is pleased to report its second quarter results highlighted by continued operational momentum at Leismer, strong Free Cash Flow and execution on its return of capital commitment through share repurchases. Athabasca is uniquely positioned as a low leveraged company generating significant Free Cash Flow through its low-decline, oil weighted asset base.

## Q2 2023 and Recent Corporate Highlights

- **Production:** ~34,000 boe/d (93% Liquids) consisting of ~29,000 bbl/d in Thermal Oil and ~5,000 boe/d in Light Oil. The Light Oil facilities were temporarily shut-in during May in response to the Alberta wildfires. No damage was sustained and production was fully restored in June. The Company is maintaining annual guidance of 34,500 – 36,000 boe/d, underpinned by production ramp up at Leismer throughout the remainder of 2023.
- **Cash Flow:** Consolidated Operating Income of $95 million and Adjusted Funds Flow[1] of $82 million. Cash Flow was supported by structurally stronger Western Canadian Select heavy differentials averaging US$15/bbl in Q2 (US$25/bbl Q1 2023).
- **Capital Program:** $41 million focused on advancing the Leismer expansion project in Thermal Oil. Capital guidance for the year remains at $145 million.
- **Free Cash Flow:** $40 million of Free Cash Flow supporting return of capital commitments.
- **Executing Return of Capital Commitment:** $61 million in share buybacks (20 million shares at an average price of $3.04 per share) completed since April representing 34% of the Company's annual Normal Course Issuer Bid limit.
- **Balance Sheet Strength:** Net Debt of $62 million with Liquidity of $220 million, including Cash of $132 million. The Company maintains a low level of outstanding debt.
- **Leismer Update:** Pad L8M commenced steaming in Q1 with four of the five well pairs placed on production in early June and the fifth expected to be on production in August. The asset is currently producing ~24,000 bbl/d, significantly ahead of prior production guidance. Drilling operations have recently been completed on four infill wells on Pad L7 and four well pairs on Pad L8S. These additional wells will support the expansion project that will drive growth to ~28,000 bbl/d by mid-2024. With the increased operating scale, the Company forecasts ~$5/bbl margin improvement at Leismer in 2024.

*Footnote: Refer to the "Reader Advisory" section within this news release for additional information on Non-GAAP Financial Measures (e.g. Adjusted Funds Flow, Free Cash Flow, Excess Cash Flow, Sustaining Capital, Net Debt, Liquidity) and production disclosure.*
*[1]Cash flow from operating activities in Q2 2023 was $47 million.*
*[2] Pricing Assumptions: 2023 realized prices in H1 and flat pricing of US$80 WTI, US$15 Western Canadian Select "WCS" heavy differential, C$3 AECO, and $0.75 C$/US$ FX for H2. 2024-25 flat pricing of US$85 WTI, US$12.50 WCS heavy differential, C$5 AECO, and $0.75 C$/US$ FX.*

## Strategic Update and Corporate Guidance

- **Production Guidance.** Overall production is expected to grow annually by 5 – 7% through the Company's current capital initiatives. 2023 guidance remains unchanged at 34,500 – 36,000 boe/d (93% Liquids). Athabasca's portfolio of long-life assets underpin a low corporate decline of ~5% annually.
- **Capital Guidance Intact:** The Company remains committed to executing a ~$145 million capital program this year ($120 million Thermal and $25 million Light Oil) with activity focused on advancing the expansion project at Leismer and operational readiness in Light Oil.
- **Return of Capital Commitment:** Athabasca is committed to allocating a minimum of 75% of Excess Cash Flow (Adjusted Funds Flow less Sustaining Capital) in 2023 to shareholders through share buybacks. Additional Excess Cash Flow allocation will be commodity price dependent and could include additional share repurchases dependent on valuation, further debt reduction or high return growth projects.
- **Capital Efficient Growth at Leismer:** Leismer production is currently ~24,000 bbl/d and the Company has successfully accelerated the on production dates for well pairs on Pad L8M. A facility expansion and additional drilling will support sustainable growth to ~28,000 bbl/d by mid-2024 at a competitive capital efficiency of ~$14,000/bbl/d. This project is on-track with previous guidance, will not impact the return of capital strategy and is expected to bolster future Free Cash Flow generation through enhanced margins.
- **Managing for Free Cash Flow:** Athabasca is positioned for continued margin growth in 2024 with the Leismer expansion and expected narrower WCS heavy differentials following the expected start-up of the Trans Mountain Pipeline Expansion. The Company expects to generate ~$1 Billion in Free Cash Flow[2] during the three-year timeframe of 2023-25.
- **Thermal Oil Differentiation:** Strong margins and Free Cash Flow are supported by a Thermal Oil pre-payout Crown royalty structure, with royalty rates between 5 – 9%. Leismer is estimated to remain pre-payout until 2027 and Hangingstone well into the 2030s (US$85 WTI, US$12.50 WCS differential). This results in maximum cash flow at current commodity prices and creates a significant advantage over the majority of industry oil sands projects.
- **Excellent Exposure to Commodity Upside:** Athabasca has excellent exposure to upside in commodity prices with 25% of forecasted 2023 production volumes hedged through collars, providing upside to ~US$98.50 WTI. Every $5/bbl WTI change impacts annual cash flow by ~$50 million (unhedged) and every US$5/bbl WCS differential change impacts annual cash flow by ~$80 million (unhedged).

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## Financial and Operational Highlights

| ($ Thousands, unless otherwise noted) | Three months ended June 30, 2023 | 2022 | Six months ended June 30, 2023 | 2022 |
|---|---|---|---|---|
| CONSOLIDATED | | | | |
| Petroleum and natural gas production (boe/d)(1) | 33,971 | 33,247 | 34,325 | 33,958 |
| Petroleum, natural gas and midstream sales | $ 282,614 | $ 435,678 | $ 573,355 | $ 825,102 |
| Operating Income (Loss)(1) | $ 95,118 | $ 169,255 | $ 151,653 | $ 319,895 |
| Operating Income (Loss) Net of Realized Hedging(1)(2) | $ 90,522 | $ 103,549 | $ 125,002 | $ 206,543 |
| Operating Netback ($/boe)(1) | $ 32.23 | $ 57.51 | $ 24.05 | $ 52.26 |
| Operating Netback Net of Realized Hedging ($/boe)(1)(2) | $ 30.67 | $ 35.18 | $ 19.82 | $ 33.74 |
| Capital expenditures | $ 41,432 | $ 51,191 | $ 67,794 | $ 82,120 |
| THERMAL OIL DIVISION | | | | |
| Bitumen production (bbl/d) (1) | 29,016 | 26,768 | 29,097 | 27,335 |
| Petroleum, natural gas and midstream sales | $ 265,304 | $ 399,793 | $ 534,406 | $ 760,074 |
| Operating Income (Loss)(1) | $ 81,621 | $ 131,067 | $ 123,118 | $ 251,904 |
| Operating Netback ($/bbl)(1) | $ 32.64 | $ 55.68 | $ 22.97 | $ 51.17 |
| Capital expenditures | $ 29,912 | $ 43,093 | $ 52,748 | $ 64,275 |
| LIGHT OIL DIVISION | | | | |
| Petroleum and natural gas production (boe/d)(1) | 4,955 | 6,479 | 5,228 | 6,623 |
| Percentage Liquids (%)(1) | 55% | 58% | 56% | 57% |
| Petroleum, natural gas and midstream sales | $ 24,006 | $ 53,825 | $ 53,895 | $ 98,933 |
| Operating Income (Loss)(1) | $ 13,497 | $ 38,188 | $ 28,535 | $ 67,991 |
| Operating Netback ($/boe)(1) | $ 29.92 | $ 64.77 | $ 30.16 | $ 56.72 |
| Capital expenditures | $ 10,753 | $ 1,221 | $ 12,629 | $ 9,208 |
| CASH FLOW AND FUNDS FLOW | | | | |
| Cash flow from operating activities | $ 46,914 | $ 68,535 | $ 67,451 | $ 128,397 |
| per share - basic | $ 0.08 | $ 0.12 | $ 0.11 | $ 0.23 |
| Adjusted Funds Flow(1) | $ 81,664 | $ 84,799 | $ 72,268 | $ 159,560 |
| per share - basic | $ 0.14 | $ 0.15 | $ 0.12 | $ 0.29 |
| Free Cash Flow (1) | $ 40,232 | $ 33,608 | $ 4,474 | $ 77,440 |
| NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS) | | | | |
| Net income (loss) and comprehensive income (loss) | $ 57,121 | $ 47,121 | $ 486 | $ (72,480) |
| per share - basic | $ 0.10 | $ 0.08 | $ 0.00 | $ (0.13) |
| per share - diluted(3) | $ 0.07 | $ 0.08 | $ 0.00 | $ (0.13) |
| COMMON SHARES OUTSTANDING | | | | |
| Weighted average shares outstanding - basic | 592,223,832 | 568,728,441 | 589,442,937 | 550,013,742 |
| Weighted average shares outstanding - diluted | 616,789,101 | 585,934,027 | 600,470,217 | 550,013,742 |

| As at ($ Thousands) | June 30, 2023 | December 31, 2022 |
|---|---|---|
| LIQUIDITY AND BALANCE SHEET | | |
| Cash and cash equivalents | $ 132,491 | $ 197,525 |
| Available credit facilities(4) | $ 87,838 | $ 87,838 |
| Face value of term debt(5) | $ 214,267 | $ 237,231 |

(1) Refer to the "Reader Advisory" section within this News Release for additional information on Non-GAAP Financial Measures and production disclosure.
(2) Includes realized commodity risk management loss of $4.6 million and $26.7 million for the three and six months ended June 30, 2023 (three and six months ended June 30, 2022 – loss of $65.7 million and $113.4 million).
(3) In the calculation of dilutive earnings per share for the three months ended June 30, 2023, earnings were reduced by $16.4 million to account for the impact to net income had the outstanding warrants and PSUs been converted to equity.
(4) Includes available credit under Athabasca's Credit Facility and Unsecured Letter of Credit Facility.
(5) The face value of the term debt at June 30, 2023 was US$162 million (December 31, 2022 – US$175 million) translated into Canadian dollars at the June 30, 2023 exchange rate of US$1.00 = C$1.3240 (December 31, 2022 – C$1.3544).

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## Operations Update

### Thermal Oil

Bitumen production for the second quarter of 2023 averaged 29,016 bbl/d. The Thermal Oil division generated Operating Income of $82 million ($33.79/bbl at Leismer and $29.20/bbl at Hangingstone) during the period with capital expenditures of $30 million, primarily related to drilling operations and progressing the facility expansion at Leismer.

*Leismer*

At Leismer, four new well pairs at Pad L8M were placed on production in early June supporting production of ~24,000 bbl/d with a current steam oil ratio ("SOR") of less than 3x. The fifth new well pair on Pad L8M is scheduled to be placed on production in early August. The five well pairs are expected to ramp-up to ~6,000 bbl/d over six months and maintain a stable production profile for approximately five years. During the quarter, drilling commenced on the final four well pairs at Pad L8S and four infill wells on Pad L7. These wells have been rig released ahead of schedule and surface facilities are expected be completed this fall. Preliminary drilling results confirm consistent high quality sands. These additional new wells are expected to support production in 2024 and beyond.

The facility expansion project continues to progress and will support sustainable growth up to ~28,000 bbl/d by mid-2024. This production level can be held with modest sustaining capital (~$6/bbl) for many years into the future. The Company is able to leverage existing excess steam capacity and has been proactive in acquiring long lead equipment. The project is budgeted at a competitive capital efficiency of ~$14,000/bbl/d and is expected to enhance margins by ~$5/bbl from current levels through increased operating scale. The Company maintains future optionality for additional expansion projects that could support Leismer growth to its regulatory approved capacity of 40,000 bbl/d.

Leismer has a significant unrecovered capital balance of ~$1.4 billion (2022 year-end) which ensures a low Crown royalty framework as the asset is estimated to remain pre-payout until 2027 (US$85 WTI, US$12.50 WCS differential).

*Hangingstone*

At Hangingstone, initial work on the Pad AA extension has begun in anticipation of drilling two future sustaining well pairs in 2024 to maintain base production. Non-condensable gas co-injection continues to aid in pressure support and reduced energy usage. Hangingstone's SOR averaged 3.6x in the first half of 2023. Cost initiatives completed since 2020 and the lower SOR supported a $29.20/bbl Operating Netback during the quarter.

### Light Oil

Production for the second quarter of 2023 averaged 4,955 boe/d (55% Liquids). The Light Oil division generated Operating Income of $14 million ($29.92/boe) during the period with capital expenditures of $11 million. Activity was focused on operational readiness in advance of the upcoming drilling season.

In the Duvernay oil window at Kaybob East and Two Creeks the Company has extended production history from 27 wells de-risking an inventory of 290 gross future locations. The wells have consistently supported the Company's type curve expectations with IP365's averaging ~550 boe/d per well, ~85% Liquids (latest 12 wells since 2020), demonstrating the significant potential of the asset.

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The Light Oil land position has no near-term expiries and is ready for future development with ~850 gross Montney and Duvernay locations.

Light Oil operations were temporarily affected by the Alberta wildfires in the second quarter of 2023. As a precautionary measure Athabasca shut-in its facilities temporarily for a portion of May. No damage was sustained to well sites or infrastructure and production was fully restored in June.

## Business Environment & Outlook

Global oil benchmarks have weakened year over year as global recession concerns weighed on commodities. However, the war in Ukraine has amplified the emphasis on energy security and sanctions continue to alter energy flows across the globe. Athabasca maintains a constructive outlook on oil prices supported by years of industry underinvestment, OPEC+ cuts and demand trends moving higher.

Canadian WCS heavy differentials narrowed significantly in the second quarter with differentials improving to US$15.08/bbl, compared to US$24.77/bbl in the first quarter of 2023. The supply-demand outlook for heavy barrels is expected to be supported by the continued OPEC+ production cuts, the start-up of the Trans Mountain Expansion pipeline (590,000 bbl/d) and the start-up of new global heavy oil refining capacity, specifically Pemex's Dos Bocas 340,000 bbl/d refinery. These factors are expected to improve the strength of WCS prices into the second half of 2023 and 2024.

## 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.

For more information, please contact:


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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”, “project”, “continue”, “maintain”, “estimate”, “expect”, “will”, “target”, “forecast”, “could”, “intend”, “potential”, “guidance”, “outlook” and similar expressions suggesting future outcome 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: our strategic plans; future debt levels and repayment plans; the allocation of future capital; timing and quantum for shareholder returns including share buybacks; the terms of our NCIB program; our drilling plans in Leismer; Leismer ramp-up to expected production rates; timing of Leismer’s pre-payout royalty status; Adjusted Funds Flow and Free Cash Flow in 2023 to 2025; type well economic metrics; forecasted daily production and the composition of production; our outlook in respect of the Corporation’s business environment, including in respect of the Trans Mountain pipeline expansion and new global heavy oil refining capacity; and other matters.

In addition, information and statements in this News Release 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. With respect to forward-looking information contained in this News Release, assumptions have been made regarding, among other things: commodity prices; 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. Certain other 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, 2022 (which is respectively referred to herein as the "McDaniel Report”).

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 Revised Annual Information Form (“AIF”) dated May 11, 2023 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; statutes and regulations regarding the environment; regulatory environment and changes in applicable law; gathering and processing facilities, pipeline systems and rail; reputation and public perception of the oil and gas sector; environment, social and governance goals; political uncertainty; state of capital markets; ability to finance capital requirements; access to capital and insurance; abandonment and reclamation costs; continued impact of the COVID-19 pandemic; changing demand for oil and natural gas products; anticipated benefits of acquisitions and dispositions; royalty regimes; foreign exchange rates and interest rates; reserves; hedging; operational dependence; operating costs; project risks; supply chain disruption; labour supply, financial assurances; diluent supply; third party credit risk; Indigenous claims; reliance on key personnel and operators; income tax; cybersecurity; advanced technologies; hydraulic fracturing; liability management; seasonality and weather conditions; unexpected events; internal controls; limitations of 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, including level of indebtedness, restrictions in our debt instruments, additional indebtedness and issuance of additional securities. Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this News Release could also have adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking information are reasonable based on information available to it on the date such forward-looking information are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking information, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements.

Also included in this News Release are estimates of Athabasca's 2023 and 2023-25 outlook which are based on the various assumptions as to production levels, commodity prices, 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 and is included to provide readers with an understanding of the Company’s outlook. 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 outlook and forward-looking information contained in this New Release was made as of the date of this News release and the Company disclaims any intention or obligations to update or revise such outlook and/or forward-looking information, 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**

Test Results and Initial Production Rates: The well test results and initial production rates provided herein should be considered to be preliminary, except as otherwise indicated. Test results and initial production rates disclosed herein may not necessarily be indicative of long-term performance or of ultimate recovery.

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**Reserves 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, 2022. There are numerous uncertainties inherent in estimating quantities of bitumen, light crude oil and medium crude oil, tight oil, conventional natural gas, shale 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. Reserves figures described herein have been rounded to the nearest MMbbl or MMboe. For additional information regarding the consolidated reserves and information concerning the resources of the Company as evaluated by McDaniel in the McDaniel Report, please refer to the Company's AIF.

Reserve Values (i.e. Net Asset Value) is calculated using the estimated net present value of all future net revenue from our reserves, before income taxes discounted at 10%, as estimated by McDaniel effective December 31, 2022 and based on average pricing of McDaniel, Sproule and GLJ as of January 1, 2023.

The 700 gross total Duvernay drilling locations referenced include: 5 proved undeveloped locations and 77 probable undeveloped locations for a total of 82 booked locations with the balance being unbooked locations. The 290 gross Duvernay drilling locations at Kaybob East and Two Creeks referenced include: 5 proved undeveloped locations and 59 probable undeveloped locations for a total of 64 booked locations with the balance being unbooked locations. The 150 gross Montney drilling locations referenced include: 48 proved undeveloped locations and 50 probable undeveloped locations for a total of 98 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, 2022 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, commodity prices, provincial fiscal and royalty policies, costs, actual drilling results, additional reservoir information that is obtained and other factors.

**Non-GAAP and Other Financial Measures, and Production Disclosure**

The "Adjusted Funds Flow", "Adjusted Funds Flow per Share", "Free Cash Flow", "Light Oil Operating Income", "Light Oil Operating Netback", "Thermal Oil Operating Income", "Thermal Oil Operating Netback", "Consolidated Operating Income", "Consolidated Operating Netback", "Consolidated Operating Income Net of Realized Hedging", "Consolidated Operating Netback Net of Realized Hedging", "Cash Transportation & Marketing Expenses", "Excess Cash Flow" and "Sustaining Capital" financial measures contained in this News Release do not have standardized meanings which are prescribed by IFRS and they are considered to be non-GAAP financial measures or ratios. 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. "Net Debt" and "Liquidity" are supplementary financial measures. The Leismer and Hangingstone operating results are a supplementary financial measure that when aggregated, combine to the Thermal Oil segment results and the Greater Placid and Greater Kaybob operating results are supplementary financial measures that when aggregated, combine to the Light Oil segment results.

Adjusted Funds Flow, Adjusted Funds Flow Per Share and Free Cash Flow

Adjusted Funds Flow and Free Cash Flow are non-GAAP financial measures and are 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 and Free Cash Flow measures allow 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 a non-GAAP financial ratio calculated as Adjusted Funds Flow divided by the applicable number of weighted average shares outstanding. Adjusted Funds Flow and Free Cash Flow are calculated as follows:

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| ($ Thousands) | 2023 | 2022 | 2023 | 2022 |
| Cash flow from operating activities | $ 46,914 | $ 68,535 | $ 67,451 | $ 128,397 |
| Changes in non-cash working capital | 34,630 | 16,353 | 16,600 | 30,706 |
| Settlement of provisions | 120 | (89) | 794 | 457 |
| Long-term deposit | - | - | (12,577) | - |
| ADJUSTED FUNDS FLOW | 81,664 | 84,799 | 72,268 | 159,560 |
| Capital expenditures | (41,432) | (51,191) | (67,794) | (82,120) |
| FREE CASH FLOW | $ 40,232 | $ 33,608 | $ 4,474 | $ 77,440 |

*Footnote: Refer to the "Reader Advisory" section within this news release for additional information on Non-GAAP Financial Measures (e.g. Adjusted Funds Flow, Free Cash Flow, Excess Cash Flow, Sustaining Capital, Net Debt, Liquidity) and production disclosure.*

*[1]Cash flow from operating activities in Q2 2023 was $47 million.*

*[2] Pricing Assumptions: 2023 realized prices in H1 and flat pricing of US$80 WTI, US$15 Western Canadian Select "WCS" heavy differential, C$3 AECO, and $0.75 C$/US$ FX for H2. 2024-25 flat pricing of US$85 WTI, US$12.50 WCS heavy differential, C$5 AECO, and $0.75 C$/US$ FX.*

*Footnote: Refer to the "Reader Advisory" section within this news release for additional information on Non-GAAP Financial Measures (e.g. Adjusted Funds Flow, Free Cash Flow, Excess Cash Flow, Sustaining Capital, Net Debt, Liquidity) and production disclosure.*
*[1]Cash flow from operating activities in Q2 2023 was $47 million.*
*[2] Pricing Assumptions: 2023 realized prices in H1 and flat pricing of US$80 WTI, US$15 Western Canadian Select "WCS" heavy differential, C$3 AECO, and $0.75 C$/US$ FX for H2. 2024-25 flat pricing of US$85 WTI, US$12.50 WCS heavy differential, C$5 AECO, and $0.75 C$/US$ FX.*

Light Oil Operating Income and Operating Netback

The non-GAAP measure Light Oil Operating Income in this News Release is calculated by subtracting the Light Oil Segments royalties, operating expenses and transportation & marketing expenses from petroleum and natural gas sales which is the most directly comparable GAAP measure. The Light Oil Operating Netback per boe is a non-GAAP financial ratio calculated by dividing the Light Oil Operating Income by the Light Oil production. 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 Light Oil Operating Income is calculated using the Light Oil Segments GAAP results, as follows:

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| **($ Thousands)** | **2023** | **2022** | **2023** | **2022** |
| Petroleum and natural gas sales | $ 24,006 | $ 53,825 | $ 53,895 | $ 98,933 |
| Royalties | (1,337) | (5,610) | (6,893) | (11,479) |
| Operating expenses | (7,095) | (7,743) | (14,024) | (14,722) |
| Transportation and marketing | (2,077) | (2,284) | (4,443) | (4,741) |
| LIGHT OIL OPERATING INCOME | $ 13,497 | $ 38,188 | $ 28,535 | $ 67,991 |

Thermal Oil Operating Income and Operating Netback

The non-GAAP measure Thermal Oil Operating Income in this News Release is calculated by subtracting the Thermal Oil segments cost of diluent blending, royalties, operating expenses and cash transportation & marketing expenses from heavy oil (blended bitumen) and midstream sales which is the most directly comparable GAAP measure. The Thermal Oil Operating Netback per boe is a non-GAAP financial ratio calculated by dividing the respective projects Operating Income by its respective bitumen sales volumes. 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 Thermal Oil Operating Income is calculated using the Thermal Oil Segments GAAP results, as follows:

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| **($ Thousands)** | **2023** | **2022** | **2023** | **2022** |
| Heavy oil (blended bitumen) and midstream sales | $ 265,304 | $ 399,793 | $ 534,406 | $ 760,074 |
| Cost of diluent | (114,430) | (141,685) | (263,363) | (281,596) |
| Total bitumen and midstream sales | 150,874 | 258,108 | 271,043 | 478,478 |
| Royalties | (10,944) | (55,911) | (17,557) | (88,407) |
| Operating expenses | (39,605) | (51,442) | (87,374) | (96,938) |
| Cash transportation and marketing[(1)] | (18,704) | (19,688) | (42,994) | (41,229) |
| THERMAL OIL OPERATING INCOME | $ 81,621 | $ 131,067 | $ 123,118 | $ 251,904 |

*(1) Cash transportation and marketing excludes non-cash costs of $0.6 million and $1.1 million for the three and six months ended June 30, 2023 (three and six months ended June 30, 2022 - $0.6 million and $1.1 million).*

Consolidated Operating Income and Consolidated Operating Income Net of Realized Hedging and Operating Netbacks

The non-GAAP measures of Consolidated Operating Income including or excluding realized hedging in this News Release are calculated by adding or subtracting realized gains (losses) on commodity risk management contracts (as applicable), royalties, the cost of diluent blending, operating expenses and cash transportation & marketing expenses from petroleum, natural gas and midstream sales which is the most directly comparable GAAP measure. The Consolidated Operating Netbacks including or excluding realized hedging per boe are non-GAAP ratios calculated by dividing Consolidated Operating Income including or excluding hedging by the total sales volumes and are presented on a per boe basis. The Consolidated Operating Income and Consolidated Operating Netbacks including or excluding realized hedging 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 (as applicable).

| | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| **($ Thousands)** | **2023** | **2022** | **2023** | **2022** |
| Petroleum, natural gas and midstream sales[(1)] | $ 289,310 | $ 453,618 | $ 588,301 | $ 859,007 |
| Royalties | (12,281) | (61,521) | (24,450) | (99,886) |
| Cost of diluent[(1)] | (114,430) | (141,685) | (263,363) | (281,596) |
| Operating expenses | (46,700) | (59,185) | (101,398) | (111,660) |
| Cash transportation and marketing[(2)] | (20,781) | (21,972) | (47,437) | (45,970) |
| Operating Income | 95,118 | 169,255 | 151,653 | 319,895 |
| Realized gain (loss) on commodity risk management contracts | (4,596) | (66,706) | (26,651) | (113,352) |
| OPERATING INCOME NET OF REALIZED HEDGING | $ 90,522 | $ 103,549 | $ 125,002 | $ 206,543 |

*(1) Non-GAAP measure includes intercompany NGLs (i.e. condensate) sold by the Light Oil segment to the Thermal Oil segment for use as diluent that is eliminated on consolidation.*

*(2) Cash transportation and marketing excludes non-cash costs of $0.6 million and $1.1 million for the three and six months ended June 30, 2023 (three and six months ended June 30, 2022 - $0.6 million and $1.1 million).*

*Footnote: Refer to the "Reader Advisory" section within this news release for additional information on Non-GAAP Financial Measures (e.g. Adjusted Funds Flow, Free Cash Flow, Excess Cash Flow, Sustaining Capital, Net Debt, Liquidity) and production disclosure.*

*[1]Cash flow from operating activities in Q2 2023 was $47 million.*

*[2] Pricing Assumptions: 2023 realized prices in H1 and flat pricing of US$80 WTI, US$15 Western Canadian Select "WCS" heavy differential, C$3 AECO, and $0.75 C$/US$ FX for H2. 2024-25 flat pricing of US$85 WTI, US$12.50 WCS heavy differential, C$5 AECO, and $0.75 C$/US$ FX.*

Cash Transportation & Marketing Expenses

The Cash Transportation & Marketing Expense financial measure contained in this News Release is calculated by subtracting the non-cash Transportation & Marketing Expense as reported in the Consolidated Statement of Cash Flows from the Transportation & Marketing Expense as reported in the Consolidated Statement of Income (Loss) and is considered to be a non-GAAP financial measure.

Excess Cash Flow and Sustaining Capital

The Excess Cash Flow and Sustaining Capital measures allow management and others to evaluate the Company's ability to return capital to Shareholders. Sustaining Capital is managements assumption of the required capital to maintain the Company's production base. The Excess Cash Flow measure is calculated by Adjusted Funds Flow less Sustaining Capital.

Net Debt

Net Debt is defined as the face value of term debt, plus accounts payable and accrued liabilities, plus current portion of provisions and other liabilities less current assets, and excluding risk management contracts.

Liquidity

Liquidity is defined as cash and cash equivalents plus available credit capacity.

Production volumes details

| | | Three months ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|---|
| **Production** | | **2023** | **2022** | **2023** | **2022** |
| Greater Placid: | | | | | |
| Condensate NGLs | bbl/d | 720 | 1,002 | 767 | 1,051 |
| Other NGLs | bbl/d | 350 | 384 | 376 | 410 |
| Natural gas(1) | mcf/d | 9,563 | 11,337 | 9,650 | 11,750 |
| Total Greater Placid | boe/d | 2,664 | 3,275 | 2,752 | 3,419 |
| Greater Kaybob: | | | | | |
| Oil(2) | bbl/d | 1,412 | 2,019 | 1,493 | 1,995 |
| Other NGLs | bbl/d | 249 | 353 | 284 | 338 |
| Natural gas(1) | mcf/d | 3,782 | 4,988 | 4,198 | 5,224 |
| Total Greater Kaybob | boe/d | 2,291 | 3,204 | 2,476 | 3,204 |
| Light Oil: | | | | | |
| Oil(2) | bbl/d | 1,412 | 2,019 | 1,493 | 1,995 |
| Condensate NGLs | bbl/d | 720 | 1,002 | 767 | 1,051 |
| Oil and condensate NGLs | bbl/d | 2,132 | 3,021 | 2,260 | 3,046 |
| Other NGLs | bbl/d | 599 | 737 | 660 | 748 |
| Natural gas(1) | mcf/d | 13,345 | 16,325 | 13,848 | 16,974 |
| Total Light Oil division | boe/d | 4,955 | 6,479 | 5,228 | 6,623 |
| Total Thermal Oil division bitumen | bbl/d | 29,016 | 26,768 | 29,097 | 27,335 |
| Total Company production | boe/d | 33,971 | 33,247 | 34,325 | 33,958 |

*(1) Comprised of 99% or greater of shale gas, with the remaining being conventional natural gas.*
*(2) Comprised of 99% or greater of tight oil, with the remaining being light and medium crude oil*

This News Release also makes reference to Athabasca's forecasted total average daily production of 34,500 – 36,000 boe/d for 2023. Athabasca expects that ~86% of that production will be comprised of bitumen, ~6% shale gas, ~4% tight oil, ~2% condensate natural gas liquids and ~2% other natural gas liquids.

This News Release makes reference to Athabasca's latest 12 wells at Kaybob East and Two Creeks have seen average productivity of ~550 boe/d IP365s (85% Liquids), which is comprised of ~80% tight oil, ~15% shale gas and ~5% NGLs.

Liquids is defined as bitumen, light crude oil, medium crude oil and natural gas liquids.

*Footnote: Refer to the "Reader Advisory" section within this news release for additional information on Non-GAAP Financial Measures (e.g. Adjusted Funds Flow, Free Cash Flow, Excess Cash Flow, Sustaining Capital, Net Debt, Liquidity) and production disclosure.*
*[1]Cash flow from operating activities in Q2 2023 was $47 million.*
*[2] Pricing Assumptions: 2023 realized prices in H1 and flat pricing of US$80 WTI, US$15 Western Canadian Select "WCS" heavy differential, C$3 AECO, and $0.75 C$/US$ FX for H2. 2024-25 flat pricing of US$85 WTI, US$12.50 WCS heavy differential, C$5 AECO, and $0.75 C$/US$ FX.*