ATHABASCA
OIL CORPORATION

FOR IMMEDIATE RELEASE – July 28, 2021

Athabasca Oil Corporation Announces 2021 Second Quarter Results

CALGARY – Athabasca Oil Corporation (TSX: ATH) ("Athabasca" or the "Company") is pleased to report its 2021 second quarter results that demonstrate the quality of its asset base. Athabasca is advancing the refinancing of its debt that will allow shareholders to capture unparalleled cashflow generation potential from its long reserve life, oil weighted asset base.

Q2 Highlights

- **Production:** ~34,650 boe/d including ~26,450 bbl/d in Thermal Oil and ~8,200 boe/d in Light Oil.
- **Record Operating Income**: $93 million ($31.09/boe) driven by strong oil prices and 90% liquids weighting.
- **Record Operating Netbacks:** $30.05/bbl in Thermal Oil and $34.23/boe in Light Oil.
- **Capital Expenditures:** $23 million focused on high-value Leismer projects to sustain production.
- **Adjusted Funds Flow:** $50 million ($0.09 per share) and record Free Cash Flow of $28 million.

Recent Operational Highlights

- **Leismer:** Two L6 infills and well pair L7P6 brought on production in June. Finished drilling Pad L8 with steaming to commence in Q4. The 5-well pad will ramp up to >5,000 bbl/d in 2022 and has project economics of ~$310 million NPV10 (US$60 WTI flat pricing).
- **Hangingstone:** Production restored to pre shut-in levels and averaged ~9,500 bbl/d during Q2. Materially improved resiliency through cost initiatives with a ~US$31 WCS operating break-even. Commissioned a truck-in terminal with capacity of ~5,000 bbl/d and is expected to generate ~$5 million in additional annual cash flow.
- **Light Oil:** Focused on free cash flow generation; Kaybob East & Two Creeks Duvernay wells screen as top liquids producers with IP180s and IP365s averaging 725 boe/d (85% Liquids) and ~550 boe/d (83% Liquids).
- **Thermal Carbon Capture:** Continuing to advance a scoping study with Entropy Inc. to determine feasibility of a carbon capture module at Leismer with ongoing evaluation of local storage and carbon trunkline options.

Financial Update and 2021 Outlook (Strip Pricing July 5th)

- **Cash:** $153 million unrestricted cash forecasted to grow to ~$210 million by year-end; an additional $134 million of restricted cash and deposits.
- **EBITDA & Cash Flow:** 2021 Adjusted EBITDA of ~$235 million (~$175 million of Adjusted Funds Flow); unhedged annual EBITDA sensitivity of ~$70 million for every US$5/bbl move in oil prices.
- **Net Debt:** $383 million with Net Debt to 2021 Adjusted EBITDA of 1.6x.
- **Production:** Trending towards the upper end of 32,000 – 34,000 boe/d (~90% Liquids) annual guidance.
- **Low Sustaining Capital:** Unchanged $100 million capital budget funded within Adjusted Funds Flow and generating ~$75 million of Free Cash Flow.

Underpinned by strong asset performance and cashflow generation, the Company is focused on the refinancing of its balance sheet. The Company's goals include lowering the overall quantum of debt and providing multi-year funding certainty.

Footnote: Refer to the "Reader Advisory" section within this news release for additional information on Non-GAAP Financial Measures (e.g. Operating Income, Adjusted Funds Flow, Free Cash Flow, Net Debt, Adjusted EBITDA) and production disclosure. 2021 strip pricing at July 5th, 2021: US$68 WTI, US$13 WCS differentials, C$3.39/mcf AECO, 0.81 US$/C$ FX.

Business Environment and the Recovery from COVID-19

The COVID-19 pandemic had a significant negative impact on global commodity prices due to a reduction in oil demand as countries around the world enacted emergency measures to combat the spread of the virus. The Company took swift action in response to the pandemic and the economic crisis.

Commodity prices have improved with OPEC+ producers reducing production allowing for inventories to re-balance. Global demand is approaching pre-pandemic levels and inventories are below the 5-year average. Supply and demand fundamentals are now supporting a much stronger oil futures market. The recent OPEC+ supply agreement is expected to keep the market in deficit and guidance for higher capacity will be needed in coming years given growing under-investment (Goldman Sachs Commodity Research).

In Alberta, physical markets and regional benchmark prices (e.g. Western Canadian Select "WCS" heavy oil) have strengthened with higher WTI prices. Athabasca expects current WCS differentials to remain stable with muted industry growth and improving basin egress (including Enbridge Line 3 replacement H2 2021). There is strong demand for heavy oil from US Gulf Coast refineries as they face structural declines in global heavy oil supply (Venezuela and Mexico). Athabasca believes conditions have emerged for WCS heavy oil to be among the most valuable global crude benchmarks.

Outlook and Balance Sheet Update

Athabasca continues to advance the refinancing of its US$450 million Second Lien Notes ("2022 Notes"). The recent strength in the high yield market, improving global oil prices and the successful debt issuances of peers provide a constructive environment to complete a normal course issuance of new notes.

Unrestricted cash as at June 30th totaled $153 million providing a strong liquidity position that is expected to grow to ~$210 million at year-end (Strip Pricing July 5th). The Company also has $134 million of restricted cash and deposits. Net debt at quarter end was $383 million with Net Debt to 2021 expected Adjusted EBITDA of 1.6x. The Company is committed to allocating Free Cash Flow to debt reduction in order to achieve its long-term debt targets of <1.5x Net Debt to Adjusted EBITDA at US$55 WTI.

Athabasca's long-life reserves provides for significant asset coverage. Under flat US$60 WTI the Company estimates a 2020 year-end Proved Developed Producing ("PDP") NPV10 of ~$875 million (US$12.50 WCS differentials & 0.80 US$/C$ FX). Management anticipates that the 2021 Leismer sustaining capital projects will drive strong reserve bookings which will replace 2021 corporate production.

The $100 million unchanged 2021 capital program is fully funded within forecasted Adjusted Funds Flow of ~$175 million (US$68 WTI & US$13 WCS differential) and is expected to generate ~$75 million of Free Cash Flow. Capital activity is focused on sustaining production at the Company's cornerstone Leismer asset. The Company's operational results support the strong start to the year with production trending towards the upper end of its annual guidance of 32,000 – 34,000 boe/d (90% Liquids). The Company expects it can sustain this level of production with an annual capital program of ~$125 million.

The Company is planning a wholistic debt refinancing that will utilize cash on hand, a reestablished reserves based credit facility and a lower quantum of new notes. Athabasca will continue with its hedging policy targeting up to 50% of corporate production with an emphasis on securing funds flow to protect its base sustaining capital program.

Footnote: Refer to the "Reader Advisory" section within this news release for additional information on Non-GAAP Financial Measures (e.g. Operating Income, Adjusted Funds Flow, Free Cash Flow, Net Debt, Adjusted EBITDA) and production disclosure. 2021 strip pricing at July 5th, 2021: US$68 WTI, US$13 WCS differentials, C$3.39/mcf AECO, 0.81 US$/C$ FX.

Financial and Operational Highlights

($ Thousands, unless otherwise noted)	Three months ended June 30, 2021	2020	Six months ended June 30, 2021	2020
CONSOLIDATED				
Petroleum and natural gas production (boe/d)(1)	34,659	27,067	34,531	31,812
Operating Income (Loss)(1)	$ 93,196	$ (18,269)	$ 159,124	$ (38,597)
Operating Income (Loss) Net of Realized Hedging(1)(2)	$ 75,372	$ 6,166	$ 120,187	$ 7,264
Operating Netback ($/boe)(1)	$ 31.09	$ (7.05)	$ 26.00	$ (6.44)
Operating Netback Net of Realized Hedging ($/boe)(1)(2)	$ 25.14	$ 2.37	$ 19.64	$ 1.21
Capital expenditures	$ 22,628	$ 5,811	$ 58,182	$ 82,057
Capital Expenditures Net of Capital-Carry(1)	$ 22,628	$ 5,811	$ 58,182	$ 59,317
THERMAL OIL DIVISION				
Bitumen production (bbl/d)	26,433	17,601	26,193	22,958
Operating Income (Loss)(1)	$ 67,568	$ (24,619)	$ 109,736	$ (57,730)
Operating Netback ($/bbl)(1)	$ 30.05	$ (14.21)	$ 23.81	$ (13.17)
Capital expenditures	$ 21,388	$ 4,722	$ 54,402	$ 22,418
LIGHT OIL DIVISION				
Petroleum and natural gas production (boe/d)(1)	8,226	9,466	8,338	8,854
Percentage Liquids (%)(1)	57%	62%	57%	61%
Operating Income (Loss)(1)	$ 25,628	$ 6,350	$ 49,388	$ 19,133
Operating Netback ($/boe)(1)	$ 34.23	$ 7.37	$ 32.72	$ 11.88
Capital expenditures	$ 544	$ 1,089	$ 1,512	$ 59,617
Capital Expenditures Net of Capital-Carry(1)	$ 544	$ 1,089	$ 1,512	$ 36,877
CASH FLOW AND FUNDS FLOW				
Cash flow from operating activities	$ 36,183	$ (31,186)	$ 37,321	$ (34,207)
per share - basic	$ 0.07	$ (0.06)	$ 0.07	$ (0.06)
Adjusted Funds Flow(1)	$ 50,228	$ (16,214)	$ 69,189	$ (44,097)
per share - basic	$ 0.09	$ (0.03)	$ 0.13	$ (0.08)
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)				
Net income (loss) and comprehensive income (loss)	$ (13,944)	$ (65,335)	$ (31,416)	$ (581,816)
per share - basic	$ (0.03)	$ (0.12)	$ (0.06)	$ (1.10)
per share - diluted	$ (0.03)	$ (0.12)	$ (0.06)	$ (1.10)
COMMON SHARES OUTSTANDING				
Weighted average shares outstanding - basic	530,675,391	530,363,434	530,675,391	526,979,706
Weighted average shares outstanding - diluted	530,675,391	530,363,434	530,675,391	526,979,706

As at ($ Thousands)	June 30, 2021	December 31, 2020
LIQUIDITY AND BALANCE SHEET		
Cash and cash equivalents	$ 152,639	$ 165,201
Restricted cash	$ 90,232	$ 135,624
Available credit facilities(3)	$ 98	$ 348
Face value of long-term debt, including current portion(4)	$ 557,730	$ 572,940

(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 $17.8 million and $38.9 million for the three and six months ended June 30, 2021 (three and six months ended June 30, 2020 - $24.4 million and $45.9 million gains).
(3) Includes available credit under Athabasca's Credit Facility and Unsecured Letter of Credit Facility (see page 14 of the Company's Q2 MD&A).
(4) The face value of the 2022 Notes is US$450 million. The 2022 Notes were translated into Canadian dollars at the June 30, 2021 exchange rate of US$1.00 = C$1.2394 (December 31, 2020 – C$1.2732).

Operations Update

Thermal Oil

Bitumen production for Q2 2021 averaged 26,433 bbl/d. The Thermal Oil division generated Operating Income of $67.6 million. Q2 2021 Operating Netbacks for Leismer and Hangingstone were a record $31.76/bbl and $27.09/bbl, respectively. Thermal Oil margins have continued to improve year to date with June Operating Netbacks of ~$35/bbl and ~$32/bbl for each asset, respectively. Capital expenditures for the quarter were $21.4 million resulting in $46.2 million of Free Cash Flow.

Leismer

Bitumen production for Q2 2021 averaged 16,986 bbl/d. Current production has increased in July following the tie-in of two L6 infills and well pair L7P6 that were placed on production in late June.

During the quarter, the Company finished drilling and completions operations of five well pairs at Pad L8. The producer wells encountered the highest quality reservoir across all of Leismer's wells drilled to date. Athabasca anticipates completing the facility construction and initial steam circulation in Q4 2021 with first production in early 2022. The initial five well pairs on Pad L8 are expected to ramp-up in excess of 5,000 bbl/d in 2022. The existing pipeline will support future development for a total of 14 well pairs on Pad L8. The Company is preparing for a drilling program to commence this upcoming winter season with future wells to sustain Leismer's production.

The Company is expanding its non-condensable gas co-injection ("NCG") program across the field following successful implementation in 2020 (Pad L1 – L4) which has lowered mature pad SORs. In Q2, the Company began NCG co-injection on Pad L5 and L6.

Athabasca and Entropy Inc. are continuing to advance a scoping study to implement a carbon capture module at the Leismer central processing unit along with evaluating local storage and carbon truckline options.

Leismer has an estimated US$28 WCS 2021 operating break-even (US$12.50 WCS differential).

Hangingstone

Bitumen production for Q2 2021 averaged 9,447 bbl/d. Reservoir performance through 2021 has been strong as a result of excellent facility run time and the implementation of NCG co-injection aiding in pressure build-up and reduced energy usage. Production is expected to be supported by an additional well pair (AA03) that is currently steaming and will be placed on production in September.

In May, Athabasca amended the Hangingstone Transportation and Storage Services Agreement that resulted in a $44 million prepayment from restricted cash, a ~$5 million reduction to annual tolls and a reduction in financial assurances by ~$44 million to ~$27 million. The reduction in financial assurances unlocked restricted cash on the Company's balance sheet that was concurrently used to fund the amending prepayment.

In March 2021, the Company executed a commercial arrangement with an industry leading marketing company to construct a truck-in terminal at no cost to Athabasca. Trucking operations commenced on

Footnote: Refer to the "Reader Advisory" section within this news release for additional information on Non-GAAP Financial Measures (e.g. Operating Income, Adjusted Funds Flow, Free Cash Flow, Net Debt, Adjusted EBITDA) and production disclosure. 2021 strip pricing at July 5th, 2021: US$68 WTI, US$13 WCS differentials, C$3.39/mcf AECO, 0.81 US$/C$ FX.

schedule in July. The additional volumes are forecasted to generate ~$5 million in additional annual cash flow through a processing fee while leveraging existing volume commitments under Athabasca's transportation agreements.

In 2021, Hangingstone will have no capital allocation other than routine pump replacements and has no sustaining capital requirements for the next several years. Management's execution to date on streamlining Hangingstone's cost structure has materially improved the assets resiliency and profitability. Hangingstone has an estimated US$31 WCS operating break-even (US$12.50 WCS differential).

Light Oil

Q2 production averaged 8,226 boe/d (57% Liquids) in Q2 2021. The division generated Operating Income of $25.6 million with a record Q2 Operating Netback of $34.23/boe. Athabasca's Light Oil Netback continues to be top tier when compared to Alberta's other liquids-rich Montney and Duvernay resource producers and are supported by a high liquids weighting and low operating expenses. Capital expenditures were $0.5 million during the quarter resulting in $25.1 million of Free Cash Flow.

At Greater Placid, the asset is positioned for flexible future development with an inventory of ~150 gross drilling locations and no near-term land retention requirements. Activity will be revisited following a successful refinancing.

At Greater Kaybob, production results have been consistently strong with wells screening as top liquids producers in the basin. Well results in Two Creeks and Kaybob East have seen average productivity of ~725 boe/d IP180s (85% liquids) and ~550 boe/d IP365s (83% liquids). Under full development, well costs are expected to be less than C$7.5 million in the volatile oil window. These results coupled with a large well inventory (~700 gross drilling locations) and flexible development timing indicate significant value to Athabasca. The Kaybob area is supported by a strong Joint Development Agreement, established infrastructure and no near-term land retention requirements.

Minimal capital activity ($5 million) is planned for 2021 with operations focused on facility maintenance and readiness for Duvernay completions on three wells in 2022.

Footnote: Refer to the "Reader Advisory" section within this news release for additional information on Non-GAAP Financial Measures (e.g. Adjusted Funds Flow, Net Debt, EBITDA) and production disclosure. 2021 strip pricing at July 5th, 2021: US$68 WTI, US$13 WCS differentials, C$3.39/mcf AECO, 0.81 US$/C$ FX.

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:
Matthew Taylor
Chief Financial Officer
1-403-817-9104
mtaylor@atha.com

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”, “forecast”, “continue”, “estimate”, “expect”, “may”, “will”, “project”, “target”, “should”, “believe”, “predict”, “pursue”, “potential”, “view” and “contemplate” 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 and, except as required by applicable securities laws, the Company undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. In particular, this News Release contains forward-looking information pertaining to, but not limited to, the following: our strategic plans and Free Cash Flow potential; expected capital programs to maintain production; the Company’s 2021 Outlook, including expected unrestricted cash, EBITDA, funds flow, net debt, production outlook and capital budget and; EBITDA sensitivity; planned wholistic debt refinancing, including refinancing of its US$450 million Senior Secured Second Lien Notes; future debt levels and composition; Enbridge Line 3 replacement in-service date; timing of Leismer well on stream dates and expected benefits therefrom; our drilling plans in Leismer and L8 project economics; our completion plans for Duverney wells; expected operating break-even at Leismer and Hangingstone; timing for first oil from new well pair at Hangingstone; expected costs savings resulting from the Hangingstone truck-in terminal; expectations for WCS heavy oil to be amongst the most valuable global crude benchmarks; target net debt to Adjusted EBITDA; and other matters.

In addition, information and statements in this News Release relating to "Reserves" and associated net present values therefrom are deemed to be forward-looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves 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 complete a refinancing of its debt, 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 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, 2020 (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 Annual Information Form (“AIF”) dated March 3, 2021 and Management’s Discussion and Analysis dated July 28, 2021, 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; continued impact of the COVID-19 pandemic; ability to finance capital requirements; 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; state of capital markets; anticipated benefits of acquisitions and dispositions; 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; 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; 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.

Also included in this News Release are estimates of Athabasca's 2021 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 financial outlook 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 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.

Operating break-even reflects the estimated WCS oil price per barrel required to generate an asset level operating income of Cdn $0. Break-even is used to assess the impact of changes in WCS oil prices on operating income of an asset and could impact future investment decisions. Steam oil ratio, or SOR, measures the average volume of steam required to produce a barrel of oil. Operating break-even and SOR do not have any standardized meaning and therefore should not be used to make comparisons to similar measures presented by other issuers.

Initial Production Rates

Test Results and Initial Production Rates: The well test results and initial production rates provided in this News Release 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.

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, 2020. Disclosure of 2020 year-end PDP in this News Release represents a mechanical update by management of the McDaniel Report, using flat US$60 WTI, US$12.50 WCS differentials and 0.80 US$/C$ FX. No other updates were made to technical reserves volumes, production forecasts or capital costs from those included in the McDaniel Report as management's belief is there have not been material changes to those amounts. 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. 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.

The 700 Duvernay (Greater Kaybob) drilling locations referenced include: 7 proved undeveloped locations and 78 probable undeveloped locations for a total of 85 booked locations with the balance being unbooked locations. The 150 Montney drilling (Greater Placid) locations referenced include: 63 proved undeveloped locations and 35 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, 2020 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 Financial Measures and Production Disclosure

The "Adjusted Funds Flow", "Light Oil Operating Income", "Light Oil Operating Netback", "Light Oil Capital Expenditures Net of Capital-Carry", "Thermal Oil Operating Income (Loss)", "Thermal Oil Operating Netback", "Consolidated Operating Income", "Consolidated Operating Netback", "Consolidated Capital Expenditures Net of Capital-Carry", "Adjusted EBITDA", "Net Debt" and "Free Cash Flow" 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 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 "Advisories and Other Guidance" section within the Company's Q2 2021 MD&A includes reconciliations of these measures, where applicable, to the nearest IFRS measures.

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. Adjusted Funds Flow is calculated by adjusting for changes in non-cash working capital, restructuring expenses and settlement of provisions from cash flow from operating activities. 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 Operating Income (Loss) measures in this News Release are calculated by subtracting royalties, cost of diluent, operating expenses and cash transportation & marketing expenses from petroleum and natural gas sales and adjusting for the impacts of inventory write-downs in the first quarter of 2020 within the Thermal Oil division. The Operating Netback measures are calculated by dividing the Operating Income (Loss) by the total sales volume and is presented on a per boe basis. The Operating Income (Loss) and the Operating Netback measures allow management and others to evaluate the production results from the Company's assets. The Consolidated Operating Income (Loss) Net of Realized Hedging measure in this News Release is calculated by adding or subtracting realized gains (losses) on commodity risk management contracts, royalties, cost of diluent, operating expenses and cash transportation & marketing expenses from petroleum and natural gas sales and adjusting for the impacts of inventory write-downs in the first quarter of 2020. The Consolidated Operating Netback Net of Realized Hedging measure is calculated by dividing Consolidated Operating Income (Loss) Net of Realized Hedging by the total sales volumes and is presented on a per boe basis. The Consolidated Operating Income (Loss) Net of Realized Hedging and the Consolidated Operating Netback Net of 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.

The Consolidated Capital Expenditures Net of Capital-Carry and Light Oil Capital Expenditures Net of Capital-Carry measures in this News Release are outlined in the Company's Q2 2021 MD&A. These measures allow management and others to evaluate the true net cash outflow related to Athabasca's capital expenditures.

Net Debt is defined as face value of term debt plus accounts payable and accrued liabilities plus current portion of provisions and other liabilities less current assets.

Adjusted EBITDA is defined as Net income (loss) and comprehensive income (loss) before financing and interest expense, depreciation, depletion, impairment and taxation (recovery) expense adjusted for unrealized foreign exchange gain (loss), unrealized gain (loss) on risk management contracts, gain (loss) on revaluation of provisions and other, gain (loss) on sale of assets and non-cash stock-based compensation.

Free cash flow is defined as Adjusted Funds Flow less Consolidated Capital Expenditures.

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

Production volumes details

Production		Three months ended June 30, 2021	Three months ended June 30, 2020	Six months ended June 30, 2021	Six months ended June 30, 2020
Light Oil:					
Oil[2]	bbl/d	2,285	3,226	2,397	2,968
Condensate NGLs	bbl/d	1,440	1,916	1,489	1,697
Oil and condensate NGLs	bbl/d	3,725	5,142	3,886	4,665
Other NGLs	bbl/d	953	680	871	695
Natural gas[1]	mcf/d	21,290	21,863	21,484	20,962
Total Light Oil division	boe/d	8,226	9,466	8,338	8,854
Total Thermal Oil division bitumen	bbl/d	26,433	17,601	26,193	22,958
Total Company production	boe/d	34,659	27,067	34,531	31,812

(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 32,000 - 34,000 boe/d for 2021. Athabasca expects that approximately 78% of that production will be comprised of bitumen, 10% shale gas, 6% tight oil, 4% condensate natural gas liquids and 2% other natural gas liquids.

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

Additionally, this News Release makes reference to Athabasca's well results in Two Creeks and Kaybob East that have seen average productivity of ~725 boe/d IP180s (85% Liquids), which is comprised of ~80% tight oil, ~15% shale gas and ~5% NGLs, and ~550 boe/d (83% Liquids) IP365s, which is comprised of ~78% tight oil, ~17% shale gas and ~5% NGLs.