ATHABASCA OIL CORPORATION

FOR IMMEDIATE RELEASE
May 3, 2022

Athabasca Oil Announces 2022 First Quarter Results including Record $44 million Free Cash Flow, $110 million in Debt Redemptions and releases its Annual ESG Report

CALGARY – Athabasca Oil Corporation (TSX: ATH) ("Athabasca" or the "Company") is pleased to report its 2022 first quarter results with record Free Cash Flow and material deleveraging. Athabasca is uniquely positioned as a low leveraged company generating significant Free Cash Flow through its low-decline, oil weighted asset base.

Q1 Corporate Highlights

- **Production above Guidance:** 34,679 boe/d (92% Liquids) consisting of 27,909 bbl/d in Thermal Oil and 6,770 boe/d (57% Liquids) in Light Oil, ahead year-to-date of annual guidance of 33-34,000 boe/d.
- **Capital Expenditures:** $31 million focused on sustaining operations in Thermal Oil and three Duvernay well completions.
- **Record Cash Flow:** Record Adjusted Funds Flow ~$75 million and record Free Cash Flow ~$44 million. Continued cash flow expansion expected through 2023 as described below.
- **Record Operating Netbacks:** $48.79/bbl at Leismer, $43.48/bbl at Hangingstone and $48.92/boe in Light Oil.
- **Significant Deleveraging:** Redeemed $110 million in Term Debt year-to-date (inclusive of outstanding redemption notices), achieving ~50% of US$175 million debt reduction target which is anticipated to be reached in H1 2023. Low current Net Debt of ~$127 million.
- **Unlocking Shareholder Value:** Committed to further enhance shareholder returns by utilizing Free Cash Flow and cash balances for share buy-backs or dividends once debt target is achieved.

Operational Highlights

- **Focus on Leismer:** The Leismer Pad L8 (5 well pairs) ramp-up is exceeding the Company's expectations and is currently producing in excess of 2,500 bbl/d. The pad is expected to reach ~5,400 bbl/d in H2 2022 and will support a ~21,000 bbl/d exit rate this year. Beginning in June, the Company anticipates spudding an additional two infill wells at Pad L6, followed by five additional well pairs at Pad L8, with new production expected in 2023. The Leismer asset is forecasted to grow to ~24,000 bbl/d over the next three years within corporate capital guidance.
- **High Margin Duvernay:** During the quarter three Duvernay wells at Two Creeks were completed with IP30's between 650 – 1,000 boe/d (averaging 840 boe/d per well, 94% Liquids), exceeding internal type curve expectations and screening as top oil wells in Alberta. The Company has a flexible development portfolio of ~850 de-risked Montney and Duvernay locations along with strategic ownership and operatorship of liquids and gas infrastructure in Greater Kaybob. These assets provide a natural hedge for the Thermal Oil division through their production of diluent and natural gas.
- **Record Netbacks:** Athabasca's oil weighted portfolio is benefiting from strong commodity prices and low cost structures. This rate of change is reflected in the Company's March netbacks: Kaybob Duvernay ~$72.25/boe, Placid Montney ~$44.25/boe, Leismer ~$61.50/bbl and Hangingstone ~$58.50/bbl.

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, Adjusted EBITDA, Net Debt) and production disclosure.

Strategic Update and Corporate Outlook

- **Maintaining 2022 Guidance.** The Company reiterates its 33,000 – 34,000 boe/d (92% Liquids) annual production guidance along with Capital Expenditure guidance of $128 million. The Company's modest 2022 capital program is indicative of long term sustaining capital that benefits from a low decline, large resource asset base.
- **Managing for Free Cash Flow.** For 2022, Athabasca forecasts Adjusted EBITDA of ~$350 million, Adjusted Funds Flow of ~$300 million and Free Cash Flow of ~$180 million (US$85 WTI, US$13.50 Western Canadian Select "WCS" heavy differential). The Company further expects to generate ~$900 million in Free Cash Flow during the three year timeframe of 2022-24 (US$85 WTI, US$12.50 WCS differential flat pricing). Every $5 WTI impacts Free Cash Flow by ~$45 million annually (unhedged). The Company's strong margins and Free Cash Flow profile is supported by $3.1 billion in tax pools and a pre-payout Crown royalty structure for its Thermal Oil assets.
- **Executing Significant Deleveraging with Clear Targets:** The Company is planning to utilize 100% of near-term Free Cash Flow to reduce its Term Debt and is anticipating being in a net cash position by year end 2022 at current commodity prices. Year-to-date the Company has redeemed a total of C$57 million (US$45 million) through open market purchases. The Company has also provided redemption notices to noteholders for an additional C$53 million (US$41 million) from warrant proceeds and the Free Cash Flow payment feature within the indenture. These redemptions are expected to be completed by mid-May. Pro forma, the Company will have redeemed and retired a total of C$110 million (US$86 million) in its Term Debt. This achieves approximately ~50% of its US$175 million debt reduction target which is anticipated to be reached in H1 2023.
- **Excellent Exposure to Commodity Price Upside:** Athabasca has retained excellent exposure to upside in commodity prices with 50% of its 2022 sales volumes unhedged, 20% of its sales hedged through collars with upside to US$115 WTI, and 30% of its sales hedged through fixed swaps at an implied US$67.50 WTI. The Company has minimal hedging in 2023 and expects lower future hedge levels to protect its base capital program as debt targets are achieved.
- **Thermal Oil Differentiation:** Athabasca's Thermal assets operate in a pre-payout Crown royalty structure, with royalty rates between 5 - 9%, and is anticipated to last beyond 2028 (US$85 WTI, US$12.50 WCS differential flat pricing). This results in maximum cash flow at current commodity prices and creates a significant advantage over the majority of Industry oil sands projects. The Company's low decline, long reserve life Thermal Oil assets are forecasted to generate ~$400 million in Operating Income in 2022 (US$85 WTI, US$13.50 WCS differential flat pricing). At current commodity prices, these assets compete exceptionally well on all cash flow metrics against top plays in North America with capital investments generating double-digit Recycle and Profit-to-Investment Ratios.
- **Unlocking Shareholder Value:** The transition of enterprise value to equity holders is materializing and is expected to unlock significant shareholder value. Athabasca is committed to further enhancing shareholder returns by utilizing Free Cash Flow and cash balances for share buy-backs or dividends once its debt target is achieved. The Company sees tremendous intrinsic value not reflected in the current share price. Additional guidance on the Company's return of capital strategy will be provided in H2 2022.

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, Adjusted EBITDA, Net Debt) and production disclosure.

Environmental, Social and Governance ("ESG") Update

- **Annual Report.** Athabasca is proud to publish its second ESG report, aligning to leading ESG standards and frameworks including Global Reporting Initiative ("GRI"), Sustainability Accounting Standards Board ("SASB") and Task Force for Climate Disclosure ("TCFD") guidelines. The report is available on the Company's website (https://www.atha.com/responsibility.html) and SEDAR (https://www.sedar.com).
- **Carbon Capture and Storage (CCS).** Athabasca has advanced its partnership with Entropy Inc. to develop and implement a carbon capture and storage project at Leismer using Entropy's proprietary CCS technology. The partnership is progressing detailed engineering plans and has developed a commercial model for investment that aligns with reducing carbon emissions and supports the Company's future aspiration of producing a net-zero oil sands barrel.
- **Environment.** The Company has a strong track record of utilizing new technology to improve environmental performance, having invested over $60 million in technology designed to mitigate GHG emissions since 2015. By 2025, Athabasca has a goal to reduce Scope 1 emissions intensity by 30% from its 2015 baseline.
- **Social.** Athabasca's safety culture is deeply embedded and the Company's total recordable injury frequency has averaged 0.2 per 200,000 man-hours over the last three years, well below industry average. The Company has also had zero reportable hydrocarbon spills for three consecutive years.
- **Governance.** Independent Board with established and robust corporate policies. The Company's ESG strategy and performance is reviewed, considered, and fully integrated at the Board level.

Annual General Meeting

Athabasca is pleased to announce that Mr. Marty Proctor and Ms. Angela Avery will stand for election as directors to the Company's Board of Directors at the upcoming virtual Annual General Meeting ("Meeting") on Wednesday, May 4, 2022 at 9:00 am (MT).

Mr. Proctor has held several senior executive positions, including most recently as President and Chief Executive Officer of Seven Generations Energy, and currently serves in various board capacities across the energy sector. He has significant expertise in operations, engineering and business strategy, and was on the management team of North American Oilsands, an original owner of lands in Athabasca's Leismer and Corner areas.

Ms. Avery is currently the Executive Vice President, External Affairs and General Counsel at WestJet and has more than 25 years' legal and business experience, and an extensive regulatory and compliance background. She served as General Counsel and VP Business Development at Athabasca from 2017 to 2020 and prior to that held senior executive roles at ConocoPhillips.

The Board would like to extend its sincere thanks to Mr. Carlos Fierro and Ms. Anne Downey who are retiring from the Board on May 4, 2022, for their years of dedicated service to Athabasca and our shareholders. Mr. Fierro and Ms. Downey have made significant contributions to the Board and its committees, including chairing the Audit Committee and Reserves Committee, respectively.

Shareholders and guests can listen to the Meeting via live webcast at:

https://web.lumiagm.com/430317815

with additional details available at:

https://www.atha.com/investors/presentation-events.html.

An archived recording of the webcast will be available on the Company's website for those unable to listen live.

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Financial and Operational Highlights

($ Thousands, unless otherwise noted)		Three months ended March 31, 2022		2021
CONSOLIDATED				
Petroleum and natural gas production (boe/d)[1]		34,679		34,401
Petroleum, natural gas and midstream sales	$	389,424	$	211,656
Operating Income (Loss)[1]	$	150,640	$	65,928
Operating Income (Loss) Net of Realized Hedging[1][2]	$	102,994	$	44,815
Operating Netback ($/boe)[1]	$	47.40	$	21.12
Operating Netback Net of Realized Hedging ($/boe)[1][2]	$	32.41	$	14.36
Capital expenditures	$	30,929	$	35,554
Free Cash Flow[1]	$	43,832	$	(16,593)
THERMAL OIL DIVISION				
Bitumen production (bbl/d)		27,909		25,949
Petroleum, natural gas and midstream sales	$	360,281	$	186,710
Operating Income (Loss)[1]	$	120,837	$	42,168
Operating Netback ($/bbl)[1]	$	47.04	$	17.85
Capital expenditures	$	21,182	$	33,014
LIGHT OIL DIVISION				
Petroleum and natural gas production (boe/d)[1]		6,770		8,452
Percentage Liquids (%)[1]		57%		57%
Petroleum, natural gas and midstream sales	$	45,108	$	34,572
Operating Income (Loss)[1]	$	29,803	$	23,760
Operating Netback ($/boe)[1]	$	48.92	$	31.24
Capital expenditures	$	7,987	$	968
CASH FLOW AND FUNDS FLOW				
Cash flow from operating activities	$	59,862	$	1,138
per share - basic	$	0.11	$	—
Adjusted Funds Flow[1]	$	74,761	$	18,961
per share - basic	$	0.14	$	0.04
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)				
Net income (loss) and comprehensive income (loss)	$	(119,601)	$	(17,472)
per share - basic	$	(0.23)	$	(0.03)
per share - diluted	$	(0.23)	$	(0.03)
COMMON SHARES OUTSTANDING				
Weighted average shares outstanding - basic		531,091,102		530,675,391
Weighted average shares outstanding - diluted		531,091,102		530,675,391

As at ($ Thousands)		March 31, 2022		December 31, 2021
LIQUIDITY AND BALANCE SHEET				
Cash and cash equivalents	$	213,534	$	223,056
Available credit facilities[3]	$	77,838	$	77,844
Face value of term debt[4]	$	396,123	$	443,730

(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 $47.6 million for the three months ended March 31, 2022 (three months ended March 31, 2021 - $21.1 million loss).

(3) Includes available credit under Athabasca's Credit Facility and Unsecured Letter of Credit Facility.

(4) The face value of the term debt at March 31, 2022 was US$317 million (December 31, 2021 – US$350 million) translated into Canadian dollars at the March 31, 2022 exchange rate of US$1.00 =C$1.2496 (December 31, 2021 – C$1.2678).

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Operations Update

Thermal Oil

Bitumen production for Q1 2022 averaged 27,909 bbl/d. The Thermal Oil division generated record Operating Income of $121 million. Q1 2022 Operating Netbacks for Leismer and Hangingstone were a record $48.79/bbl and $43.48/bbl, respectively. Capital expenditures were $21 million.

For 2022 the Company has fully hedged its Thermal Oil gas input costs through its Light Oil gas production with the balance financially hedged at C$4/mcf AECO.

Leismer

Bitumen production for Q1 2022 averaged 18,966 bbl/d and ~20,000 bbl/d in April. Leismer has a scheduled two week plant turnaround in May which is completed every four years.

At Pad L8, three wells were converted to production in January, with the remaining wells to be placed on production in early Q2. Volumes are forecasted to grow through the year as Pad L8 ramps-up to its expected plateau rate of ~5,400 bbl/d (five well pairs). Leismer is expected to exit 2022 at ~21,000 bbl/d and grow to ~24,000 bbl/d over the next three years within corporate capital guidance.

The existing L8 gathering pipeline and infrastructure will support future development for a total of 14 well pairs on Pad L8. In June the Company will spud two additional infill wells at Pad L6 followed by five additional well pairs at Pad L8. These wells will support production in 2023 and have unparalleled Profit-to-Investment Ratios (NPV/Investment) of ~10x and double-digit Recycle Ratios at current commodity prices.

The Company has expanded non-condensable gas ("NCG") co-injection across the field on mature pads supporting lower energy intensity with a current project steam oil ratio ("SOR") of ~3.2x (March 2022).

Leismer has a significant Unrecovered Capital Balance of $1.6 billion which ensures a low Crown royalty framework as the asset is forecasted to remain pre-payout until 2028 (US$85 WTI, US$12.50 WCS differential).

Hangingstone

Bitumen production for Q1 2022 averaged 8,943 bbl/d. Production during the quarter was impacted by a delay in getting service rigs for routine pump repairs. Full production has since been re-established above 9,000 bbl/d in April. NCG co-injection is aiding in pressure support and reduced energy usage and the project achieved a record low SOR of ~3.7x in February 2022.

In 2022, Hangingstone will have no capital allocation other than routine pump replacements. Strong operational performance, cost enhancements and improved commodity prices are driving competitive margins. The Hangingstone asset is expected to generate ~$130 million Operating Income in 2022 (April 4th strip pricing: US$94 WTI, US$13 WCS differential).

Light Oil

Production averaged 6,770 boe/d (57% Liquids) in Q1 2022. The business division generated Operating Income of $30 million with a record Operating Netback of$48.92/boe. Athabasca's Light Oil Netbacks continue to be top quartile when compared to Alberta's other liquids-rich Montney and Duvernay resource producers and are supported by a high liquids weighting. Capital expenditures were $8 million during the quarter.

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Placid Montney

At Greater Placid, production averaged 3,565 boe/d (43% Liquids) in Q1 2022 with an Operating Netback of $38.86/boe. Placid is positioned for flexible future development with an inventory of ~150 gross drilling locations and minimal near-term land retention requirements.

Kaybob Duvernay

At Greater Kaybob, production averaged 3,205 boe/d (72% Liquids) in Q1 2022 with an Operating Netback of $60.11/boe.

Three Duvernay wells in the oil window at Two Creeks were recently completed. IP30's for the wells were between 650 – 1,000 boe/d (averaging 840 boe/d, 94% Liquids). Athabasca's prior 12 wells at Kaybob East and Two Creeks have averaged IP180s of ~725 boe/d (85% Liquids) and IP365s of ~550 boe/d (83% Liquids). Strong well 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 operated infrastructure and minimal near-term land retention requirements. The Company remains encouraged by competitor activity and recent new entrants into the play.

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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”, “target”, “forecast”, “goal”, “aspiration”, “commit” 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: our strategic plans; future debt levels and repayment plans; the allocation of future capital; timing for shareholder returns including share buybacks and dividends, our drilling plans in Leismer; Leismer ramp-up to expected production rates; timing of Leismer’s pre-payout royalty status; the frequency of plant turnarounds at Leismer; expected operating results at Hangingstone; Adjusted EBITDA, Adjusted Funds Flow and Free Cash Flow in 2022; the impact of lower future hedge levels; type well economic metrics; forecasted daily production and the composition of production; our ESG goals; 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, 2021 (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 2, 2022 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; continued impact of the COVID-19 pandemic; state of capital markets; ability to finance capital requirements; access to capital and insurance; abandonment and reclamation costs; 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; 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.

Also included in this News Release are estimates of Athabasca's 2022 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.

Initial Production Rates

Test Results and Initial Production Rates: The well test results and initial production rates provided in this presentation 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, 2021. 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, 2021 and based on average pricing of McDaniel, Sproule and GLJ as of January 1, 2022.

The 700 Duvernay 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 locations referenced include: 39 proved undeveloped locations and 59 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, 2021 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", "Adjusted EBITDA" and "Net Debt" 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. 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 a supplementary financial measure 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:

($ Thousands)	Three months ended March 31, 2022	2021
Cash flow from operating activities	$ 59,862	$ 1,138
Changes in non-cash working capital	14,353	16,520
Settlement of provisions	546	1,303
ADJUSTED FUNDS FLOW	74,761	18,961
Capital expenditures	(30,929)	(35,554)
FREE CASH FLOW	$ 43,832	$ (16,593)

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:

($ Thousands)	Three months ended March 31, 2022	2021
Petroleum and natural gas sales	$ 45,108	$ 34,572
Royalties	(5,869)	(1,853)
Operating expenses	(6,979)	(6,712)
Transportation and marketing	(2,457)	(2,247)
LIGHT OIL OPERATING INCOME	$ 29,803	$ 23,760

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, Adjusted EBITDA, Net Debt) and production disclosure.

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:

($ Thousands)	Three months ended March 31, 2022	2021
Heavy oil (blended bitumen) and midstream sales	$ 360,281	$ 186,710
Cost of diluent	(139,911)	(83,194)
Total bitumen and midstream sales	220,370	103,516
Royalties	(32,496)	(2,172)
Operating expenses	(45,496)	(37,804)
Cash transportation and marketing[1]	(21,541)	(21,372)
THERMAL OIL OPERATING INCOME (LOSS)	$ 120,837	$ 42,168

(1) *Cash transportation and marketing excludes non-cash costs of $0.6 million for the three months ended March 31, 2022.*

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

The non-GAAP measure Consolidated Operating Income in this News Release is calculated by adding or subtracting realized gains (losses) on commodity risk management contracts, 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 Netback per boe is a non-GAAP ratio calculated by dividing Consolidated Operating Income by the total sales volumes and is presented on a per boe basis. The Consolidated Operating Income and the Consolidated Operating Netback measures allow management and others to evaluate the production results from the Company's Light Oil and Thermal Oil assets combined together including the impact of realized commodity risk management gains or losses.

($ Thousands)	Three months ended March 31, 2022	2021
Petroleum, natural gas and midstream sales[1]	$ 405,389	$ 221,282
Royalties	(38,365)	(4,025)
Cost of diluent[1]	(139,911)	(83,194)
Operating expenses	(52,475)	(44,516)
Cash transportation and marketing[2]	(23,998)	(23,619)
Operating Income	150,640	65,928
Realized gain (loss) on commodity risk management contracts	(47,646)	(21,113)
OPERATING INCOME NET OF REALIZED HEDGING	$ 102,994	$ 44,815

(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 for the three months ended March 31, 2022.*

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.

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. Current Net Debt is Net Debt as at March 31, 2022 adjusted for $29 million of warrant proceeds received in April.

Adjusted EBITDA

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

Production volumes details

Production		Three months ended March 31, 2022	2021
Greater Placid:			
Condensate NGLs	bbl/d	1,100	1,540
Other NGLs	bbl/d	436	460
Natural gas(1)	mcf/d	12,168	15,599
Total Greater Placid	boe/d	3,565	4,600
Greater Kaybob:			
Oil(2)	bbl/d	1,971	2,511
Other NGLs	bbl/d	324	327
Natural gas(1)	mcf/d	5,463	6,083
Total Greater Kaybob	boe/d	3,205	3,852
Light Oil:			
Oil(2)	bbl/d	1,971	2,511
Condensate NGLs	bbl/d	1,100	1,540
Oil and condensate NGLs	bbl/d	3,071	4,051
Other NGLs	bbl/d	760	787
Natural gas(1)	mcf/d	17,631	21,682
Total Light Oil division	boe/d	6,770	8,452
Total Thermal Oil division bitumen	bbl/d	27,909	25,949
Total Company production	boe/d	34,679	34,401

(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 33,000 - 34,000 boe/d for 2022. Athabasca expects that approximately 82% of that production will be comprised of bitumen, 8% shale gas, 5% tight oil, 3% condensate natural gas liquids and 2% other natural gas liquids.

This News Release makes reference to Athabasca's three well results in Two Creeks that have seen average productivity of ~839 boe /d IP30s (95% Liquids), which is comprised of ~94% tight oil, ~5% shale gas and ~1% NGLs. Additionally, the 12 prior Two Creeks and Kaybob East wells 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 547 boe/d, and IP360's (83% Liquids), which is comprised of ~78% tight oil, ~17% shale gas and ~5% NGLs.

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

Recycle ratio is calculated by dividing estimated project operating netbacks by finding and development costs per boe. Profit-to-Investment Ratio is a measure of a projects net value relative to its capital investment and is calculated by dividing a project's NPV10 value by its Capital. Reserve life is calculated by dividing year-end reserves with management's forecasted production guidance.