FOR IMMEDIATE RELEASE
March 3, 2021

Athabasca Oil Corporation Announces 2020 Year-end Results

CALGARY – Athabasca Oil Corporation (TSX: ATH) ("Athabasca" or the "Company") reports its 2020 year-end results and annual reserves. In a year of unprecedented challenges, Athabasca demonstrated the exceptional resilience of its low-decline assets. In 2021, Athabasca is focused on resuming its pre-COVID business plan of free cash flow generation, disciplined operations and preserving long term future projects across its portfolio. Armed with an unrestricted cash balance of $165 million, the Company is focused on refinancing its debt in order to capture the unparalleled cashflow generation potential from its long reserve life, oil weighted asset base.

Q4 2020 and 2020 Corporate Highlights

- **Production:** 34,233 boe/d (89% Liquids) in Q4 and 32,483 boe/d (88% Liquids) in 2020.
- **Adjusted Funds Flow:** $11 million in Q4 and ($19) million in 2020.
- **Capital Expenditures:** $89 million ($39 million in Light Oil and $50 million in Thermal Oil) in 2020.
- **Balance Sheet & Sustainability:** $165 million of unrestricted cash at year-end; Net Debt of $412 million representing 2.5x 2021 forecasted EBITDA (US$55 WTI/US$12.50 WCS heavy differential). The Company has an unhedged EBITDA sensitivity of ~$70 million for a US$5 move in oil price.

2020 Reserves

- **Reserves:** 1.2 billion boe Proved plus Probable (2P) Reserves, with Leismer/Corner underpinning 1 billion barrels of low risk, long reserve life resource.
- **Reserve Value (NPV10 before tax):** $508 million Proved Developed Producing and $1.6 billion Total Proved reserves under year-end 2020 price forecasts that are conservative relative to current strip commodity prices.

2021 Outlook

- **Maintaining Production with Low Sustaining Capital:** $100 million capital budget funded within forecasted funds flow; maintaining production guidance of 31,000 – 33,000 boe/d (90% Liquids).
- **Balance Sheet:** Athabasca plans to refinance its US$450 million Second Lien Notes during the year as energy credit markets continue to improve. The Company maintains strong Liquidity of $165 million that is forecasted to grow through 2021 under current strip commodity prices.
- **Thermal Oil**: Activity at Leismer will include drilling two infill wells at Pad L6 and an additional well pair at Pad L7, with an expected on stream in H2 2021. The Company also plans to drill five well pairs at Pad L8 in H1 2021. This highly economic project will support production levels in 2022 and beyond.
- **Light Oil:** No new wells are expected to be placed on-stream during the year with operations focused on maintaining low operating costs and top tier netbacks. In Q4, the Company achieved operating costs of $7.93/boe and an industry leading operating netback of $22.61/boe.

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.

Recent ESG Initiatives

- **Kitaskino Nuwenëné Wildland Provincial Park:** In late 2020, Athabasca relinquished 235,000 acres of mineral-land interests, in partnership with the Mikisew Cree First Nation and the Government of Alberta, to create the world's largest contiguous protected boreal forest area.
- **Health, Safety and Environmental Results:** The Company continued its impressive record with an industry leading TRIF (Total Recordable Injury Frequency) of 0.1 and zero recordable spills for 2020.

Business Environment and the Recovery from COVID-19

The COVID-19 pandemic that began in March 2020 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. Major initiatives included a reduction to the 2020 capital program, temporary production curtailments, partnering with service companies to reduce operating costs and reducing future financial commitments on the Keystone XL pipeline ("KXL").

In the second half of 2020, commodity prices began to improve with both OPEC+ and North American producers reducing production allowing for global inventories to fall. Economies have started to reopen with positive developments on the vaccine front and world oil demand has almost recovered to pre-pandemic levels. Supply and demand fundamentals are now supporting a much stronger oil futures market.

In Alberta, physical markets and regional benchmark prices (e.g. WCS heavy oil) have also strengthened with WTI prices and tighter differentials as a result of curtailed volumes and falling inventories. Athabasca expects current WCS differentials to remain supported by muted industry growth projects, significant Q2 turnaround programs in the oil sands, 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 are emerging for WCS heavy oil to be among the most valuable global crude benchmarks.

Long Term Egress Update

In January 2021, the US Government revoked the KXL Presidential permit and construction on the project was halted. Athabasca holds 10,000 bbl/d of capacity on KXL. This recent development does not impact the Company's current liquidity position.

Athabasca also has a 20 year firm service transportation agreement with TC Energy for 7,200 bbl/d on the existing Keystone pipeline from Hardisty to the US Gulf Coast. The Company is anticipating an update on this service availability in 2021.

The Company also has 20,000 bbl/d service on the TransMountain Expansion ("TMX") pipeline, with an expected in-service date in late 2022. The TMX service is increasingly valuable long-term capacity for Athabasca to access world markets.

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.

Balance Sheet Outlook

Athabasca plans to refinance its US$450 million Second Lien Notes during the year as energy credit markets continue to improve. The Company's 2021 capital program is fully funded within forecasted funds flow with strong free cash flow potential. Activity is focused on sustaining production at the Company's cornerstone Leismer asset. These investments will support strong underlying asset and lending value. The Company maintains liquidity of $165 million at year-end 2020 that is forecasted to grow through H2 2021 with a front-end weighted capital program. The Company's liquids weighted, long reserve life asset base supports attractive reserve coverage debt metrics with 0.9x Proved Developed Producing reserves to Total Debt and 2.7x Proved reserves to Total Debt (McDaniel NPV10 before tax reserve value / US$450 million Second Lien Notes). With strengthening oil price fundamentals the Company estimates its net debt to 2021 forecasted EBITDA at 2.5x (US$55 WTI & US$12.50 WCS heavy differential). The Company intends to remain nimble and creative in accessing the credit capital markets which could include a combination of term debt and bank debt to optimize its current capital structure. The Company's goals include providing multi-year funding certainty and lowering the overall quantum and cost of debt.

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.

Financial and Operational Highlights

($ Thousands, unless otherwise noted)	Three months ended December 31, 2020	2019	Year ended December 31, 2020	2019
CONSOLIDATED				
Petroleum and natural gas production (boe/d)	34,233	36,403	32,483	36,196
Operating Income (Loss)[(1)(2)]	$ 30,935	$ 42,881	$ 81,011	$ 233,219
Operating Netback[(1)(2)] ($/boe)	$ 9.89	$ 13.84	$ 6.73	$ 17.95
Capital expenditures	$ 17,202	$ 69,796	$ 111,640	$ 199,141
Capital Expenditures Net of Capital-Carry[(1)]	$ 17,202	$ 46,259	$ 88,900	$ 140,207
LIGHT OIL DIVISION				
Petroleum and natural gas production (boe/d)[(1)]	9,394	8,642	9,738	10,138
Percentage Liquids (%)	58%	54%	60%	54%
Operating Income (Loss)[(1)]	$ 19,542	$ 16,287	$ 62,002	$ 95,004
Operating Netback[(1)] ($/boe)	$ 22.61	$ 20.49	$ 17.40	$ 25.68
Capital expenditures	$ 117	$ 46,473	$ 61,651	$ 109,687
Capital Expenditures Net of Capital-Carry[(1)]	$ 117	$ 22,936	$ 38,911	$ 50,753
THERMAL OIL DIVISION				
Bitumen production (bbl/d)	24,839	27,761	22,745	26,058
Operating Income (Loss)[(1)]	$ 20,746	$ 28,658	$ (10,140)	$ 182,196
Operating Netback[(1)] ($/bbl)	$ 9.17	$ 12.44	$ (1.19)	$ 19.59
Capital expenditures	$ 16,915	$ 23,229	$ 49,787	$ 89,343
CASH FLOW AND FUNDS FLOW				
Cash flow from operating activities	$ 16,079	$ 32,975	$ (22,910)	$ 92,632
per share – basic	$ 0.03	$ 0.06	$ (0.04)	$ 0.18
Adjusted Funds Flow[(1)]	$ 10,753	$ 21,478	$ (18,727)	$ 154,760
per share – basic	$ 0.02	$ 0.04	$ (0.04)	$ 0.30
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)				
Net income (loss) and comprehensive income (loss)	$ (56,891)	$ (8,757)	$ (657,525)	$ 246,865
per share – basic	$ (0.11)	$ (0.02)	$ (1.24)	$ 0.47
per share – diluted	$ (0.11)	$ (0.02)	$ (1.24)	$ 0.47
COMMON SHARES OUTSTANDING				
Weighted average shares outstanding – basic	530,675,391	523,428,276	528,837,646	521,316,320
Weighted average shares outstanding – diluted	533,453,490	523,428,276	528,837,646	526,290,689

As at ($ Thousands)	Dec. 31, 2020	Dec. 31, 2019
LIQUIDITY AND BALANCE SHEET		
Cash and cash equivalents	$ 165,201	$ 254,389
Restricted cash	$ 135,624	$ 110,609
Available credit facilities[(3)]	$ 348	$ 85,815
Capital-carry receivable (current and long-term portion - undiscounted)	$ -	$ 22,740
Face value of long-term debt[(4)]	$ 572,940	$ 583,425

(1) Refer to the "Reader Advisory" section within this press release for additional information on Non-GAAP Financial Measures and production disclosure.
(2) Includes realized commodity risk management loss of $9.4 million and gain of $29.1 million for the three months and year ended December 31, 2020, respectively (three months and year ended December 31, 2019 - $2.1 million loss and $44.0 million loss).
(3) Includes available credit under Athabasca's Credit Facility and Unsecured Letter of Credit Facility (see page 15 of the MD&A).
(4) The face value of the 2022 Notes is US$450 million. The 2022 Notes were translated into Canadian dollars at the December 31, 2020 exchange rate of US$1.00 = C$1.2732 (2019 – C$1.2965).

Operations Update

Thermal Oil

Bitumen production for Q4 2020 and 2020 averaged 24,839 bbl/d and 22,745 bbl/d, respectively. 2020 production was impacted by voluntary curtailments at Leismer in Q2 and the suspension of operations at Hangingstone during Q2 and Q3 due to unprecedented low pricing. The Thermal Oil division generated Operating Income of $20.7 million and ($10.1) million in Q4 2020 and 2020, respectively. Operating Income was disproportionally impacted by extreme low pricing during Q2 and Q3 and subsequently strengthened with the return of production and stronger commodity prices in Q4 2020. Operating Netbacks for Q4 2020 were $9.17/bbl ($13.20/bbl at Leismer and -$0.29/bbl at Hangingstone). Capital expenditures for Q4 2020 and 2020 were $16.9 million and $49.8 million, respectively.

Leismer

Bitumen production for Q4 2020 and 2020 averaged 17,379 bbl/d and 18,264 bbl/d, respectively.

In 2020, Pad L7 bitumen production ramped up to ~5,000 bbl/d. The pad demonstrated the successful utilization of technologies to increase well lengths by 50% (achieving lateral lengths of ~1,250 meter). In addition to improved economics, the successful implementation of longer well pairs decreases Athabasca's pad surface footprint by ~50% in the Leismer long-term development program.

During 2020, Athabasca implemented a number of permanent costs saving measures at Leismer. A water disposal project was completed in Q1 reducing non-energy operating costs by ~$10 million on an annual basis. Additionally, non-condensable gas co-injection ("NCG") was implemented on the mature pads and in conjunction with Pad L7 has reduced the projects Steam Oil Ratio ("SOR") to 3.3x in 2020 (from 3.7x in 2019) and supported reduced emissions intensity by ~10% when compared 2019.

In 2021, capital will be focused on sustaining production at Leismer. The Company recently completed the drilling of two infill wells at Pad L6 and an additional well pair at Pad L7 with first production expected to be on stream in H2 2021. Athabasca has continued to progress project readiness for a five well-pair sustaining pad (Pad L8) and has sanctioned drilling to commence in March. The L8 project is highly economic with go-forward capital costs of $25 million and is expected to drive competitive capital efficiencies. L8 drilling operations are expected to be completed mid-year, followed by facility construction in Q3, and initial steam circulation before year-end. The Company anticipates first production in Q2 2022 with plateau rates of greater than 5,000 bbl/d in Q4 2022. The existing pipeline will support future development for up to a total of 14 well pairs on Pad L8.

Leismer has an estimated US$27/bbl WCS 2021 operating break-even (US$12.50 WCS heavy differential).

Hangingstone

Bitumen production for Q4 2020 and 2020 averaged 7,460 bbl/d and 4,481 bbl/d, respectively. Operations were suspended in April 2020 for approximately five months in response to unprecedented commodity prices.

During the summer, the Company completed Hangingstone's first major scheduled plant turnaround. Operations resumed on September 1 and the asset is expected to ramp-up to previous bitumen rates of

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.

9,000 – 9,500 bbl/d in late 2021. The reservoir is responding well and production averaged ~8,800 bbl/d in February 2021. During 2020 the Company implemented several cost saving measures reducing non-energy operating costs to ~$9/bbl and resulting in ~$7 million of permanent annual savings.

The Company received regulatory approval in 2020 for the implementation of NCG co-injection. Injection was recently implemented on two well pairs with early results demonstrating strong pressure maintenance and reduced energy intensity. The Company plans to implement this technology field-wide in 2021.

In 2021, Hangingstone will have no capital allocation other than routine pump replacements and has no sustaining capital requirements for the next several years. The asset has an estimated US$36/bbl WCS 2021 operating break-even (US$12.50 WCS heavy differential).

Light Oil

Production averaged 9,394 boe/d (58% Liquids) and 9,738 boe/d (60% Liquids) in Q4 2020 and 2020, respectively. The business division generated Operating Income of $19.5 million ($22.61/boe) and $62.0 million ($17.40/boe) during these periods. Athabasca's Light Oil Netbacks continue 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 net of capital-carry were $0.1 million and $39 million in Q4 2020 and 2020, respectively.

Placid Montney

At Placid, the Company completed and placed 10 gross Montney wells on production during the year. Well costs continue to improve with the 2020 program achieving $6.2 million drilling and completion ("D&C") costs. No capital activity is budgeted for 2021. Placid is positioned for flexible future development with an inventory of ~150 gross drilling locations and no near-term land retention requirements.

Kaybob Duvernay

At Kaybob, the Company placed 17 gross Duvernay wells on production during the year across the volatile oil window. 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). Under full development, D&C costs are expected to be less than $7.5 million in the volatile oil window. These results coupled with a large well inventory (~700 gross drilling locations across the play) and flexible development timing indicate significant value to Athabasca.

During Q1 2020, the capital-carry provision associated with the Kaybob partnership was completed, after an investment of C$1 billion over four winter drilling seasons. The play has seen significant commercial de-risking and is ready for future development. In 2021, minimal capital has been budgeted towards Kaybob until a more robust macro environment is certain. The Kabob area is supported by a strong Joint Development Agreement, established infrastructure and no near-term land retention requirements.

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 Budget and Outlook

Athabasca is forecasting a 2021 capital budget of $100 million ($95 million Thermal Oil and $5 million Light Oil). The updated budget reflects $25 million for the increased scope of drilling and commissioning Pad L8 at Leismer. The capital program will support base production levels in H2 2021 and beyond. The program is anticipated to be fully funded within 2021 forecasted funds flow with upside potential at current strip pricing. Annual production guidance is maintained between 31,000 – 33,000 boe/d (90% Liquids).

2020 Year-End Reserves

Athabasca's independent reserves evaluator, McDaniel & Associates Consultants Ltd. ("McDaniel"), prepared the year-end reserves evaluation effective December 31, 2020. The Company's 2P reserves base is 1.2 billion boe Proved plus Probable, with Leismer/Corner underpinning 1 billion barrels of low risk, long reserve life resource. McDaniel's estimates reserve value (NPV10 before tax) of $508 million Proved Developed Producing and $1.6 billion Total Proved reserves under conservative year-end 2020 price forecasts relative to the current strip commodity prices.

For additional information regarding Athabasca's reserves and resources estimates, please see "Independent Reserve and Resource Evaluations" in the Company's 2020 Annual Information Form which is available on the Company's website or on SEDAR www.sedar.com.

	Light Oil		Thermal Oil		Corporate	
	2019	2020	2019	2020	2019	2020
Reserves (mmboe)						
Proved Developed Producing	13	**14**	68	**61**	81	**76**
Total Proved	46	**37**	410	**365**	456	**403**
Proved Plus Probable	72	**73**	1,225	**1,083**	1,297	**1,156**
NPV10 BT ($MM)[1]						
Proved Developed Producing	$170	**$165**	$963	**$343**	$1,133	**$508**
Total Proved	$375	**$234**	$2,507	**$1,321**	$2,882	**$1,555**
Proved Plus Probable	$604	**$414**	$4,364	**$2,307**	$4,968	**$2,721**

1) Net present value of future net revenue before tax and at a 10% discount rate (NPV 10 before tax) for 2020 is based on an average of McDaniel, Sproule and GLJ pricing as at January 1, 2021. NPV 10BT for 2019 is based on an average of McDaniel, Sproule and GLJ pricing as at January 1, 2020.
2) Numbers in the table may not add precisely due to rounding.

Environment, Social and Governance ("ESG") Update

Athabasca believes that strong performance in health, safety, and environment is essential to achieving our business goals and meeting the needs of stakeholders. We are focused on being a valued partner in local communities and industry programs while developing Alberta's energy resources responsibly. We have developed policies, programs and strong governance practices to be consistent with these objectives.

In February 2021, the Government of Alberta announced an 143,800 hectare expansion of the Kitaskino Nuwenëné Wildland Provincial Park ("KNWP") in Northern Alberta creating the largest continuous area of protected boreal forest in the world. Athabasca relinquished ~95,000 hectares of oil sands rights to support the expansion of the KNWP.

"Since 2019, Athabasca Oil has been collaborating with the Mikisew Cree First Nation and the Government of Alberta to expand the Kitaskino Nuwenëné Wildland Park. Athabasca Oil has relinquished over 95,000 hectares of mineral rights to help make this park expansion a reality. The expansion of the park will help the province meet its biodiversity and conservation goals in this culturally and ecologically significant area. This represents a significant success for Indigenous communities, industry and Albertans."

Rob Broen, President and CEO, Athabasca Oil Corporation

The Company plans to release its inaugural ESG report in 2021.

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

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.

Reader Advisory:

This News Release contains forward-looking information that involves various risks, uncertainties and other factors. All information other than statements of historical fact is forward-looking information. The use of any of the words “anticipate”, “plan”, “continue”, “estimate”, “expect”, “may”, “will”, “project”, “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. In particular, this News Release contains forward-looking information pertaining to, but not limited to, the following: our strategic plans; the Company’s 2021 Outlook; refinancing of its US$450 million Second Lien Notes; future debt levels and composition; Trans Mountain and Keystone in-service dates; timing of Leismer well on stream dates and expected benefits therefrom; our drilling plans in Leismer; Hangingstone ramp-up to previous bitumen rates; type well economic metrics; expectations for WCS heavy oil to be amongst the most valuable global crude benchmarks; 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, 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 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.

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, 2020. 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, 2020 and based on average pricing of McDaniel, Sproule and GLJ as of January 1, 2021.

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: 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

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 Light Oil Operating Income (Loss) measure in this News Release is calculated by subtracting royalties, operating expenses and transportation & marketing expenses from petroleum and natural gas sales. The Light Oil Operating Netback measure is calculated by dividing the Light Oil Operating Income (Loss) by the Light Oil production and is presented on a per boe basis. The Light Oil Operating Income (Loss) and the Light Oil Operating Netback measures allow management and others to evaluate the production results from the Company's Light Oil assets.

The Operating Income (Loss) measure in this News Release with respect to the Leismer Project and Hangingstone Project is calculated by subtracting the cost of diluent blending, royalties, operating expenses and transportation & marketing expenses from heavy oil (i.e. blended bitumen) sales. The Thermal Oil Operating Netback measure is calculated by dividing the respective projects Operating Income (Loss) by its respective bitumen sales volumes and is presented on a per barrel basis. The Thermal Oil Operating Income (Loss) and the Thermal Oil Operating Netback measures allow management and others to evaluate the production results from the Company's Thermal Oil assets.

The Consolidated Operating Income (Loss) measure 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 transportation & marketing expenses from petroleum and natural gas sales. The Consolidated Operating Netback measure is calculated by dividing Consolidated Operating Income (Loss) by the total sales volumes and is presented on a per boe basis. The Consolidated Operating Income (Loss) and the Consolidated Operating Netback measures allow management and others to evaluate the production results from the Company's Light Oil and Thermal Oil assets combined together including the impact of realized commodity risk management gains or losses.

The 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 Q4 2020 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 current liabilities (adjusted for risk management contracts) less current assets (adjusted for risk management contracts and capital-carry receivable).

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 stock-based compensation.

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

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

Production volumes details

Production		2020 Q4	2020 Q3	2020 Q2	2020 Q1	2020 Annual	2019 Q4	2019 Q3	2019 Q2	2019 Q1	2019 Annual
Greater Placid:											
Condensate NGLs	bbl/d	1,841	2,612	1,916	1,480	1,964	1,457	1,734	2,150	2,711	2,009
Other NGLs	bbl/d	523	632	389	351	474	493	439	524	556	503
Natural gas(1)	mcf/d	17,900	19,668	14,221	12,939	16,197	15,723	17,538	20,441	22,424	19,009
Total Greater Placid	**boe/d**	**5,347**	**6,522**	**4,675**	**3,988**	**5,138**	**4,571**	**5,096**	**6,081**	**7,004**	**5,680**
Greater Kaybob:											
Oil(2)	bbl/d	2,845	3,685	3,226	2,708	3,117	2,336	2,985	2,186	2,480	2,498
Other NGLs	bbl/d	264	332	291	359	311	406	372	349	536	415
Natural gas(1)	mcf/d	5,629	7,746	7,642	7,123	7,032	7,972	9,421	9,564	10,152	9,272
Total Greater Kaybob	**boe/d**	**4,047**	**5,308**	**4,791**	**4,254**	**4,600**	**4,071**	**4,927**	**4,129**	**4,708**	**4,458**
Light Oil:											
Oil(2)	bbl/d	2,845	3,685	3,226	2,708	3,117	2,336	2,985	2,186	2,480	2,498
Condensate NGLs	bbl/d	1,841	2,612	1,916	1,480	1,964	1,457	1,734	2,150	2,711	2,009
Oil and condensate NGLs	bbl/d	4,686	6,297	5,142	4,188	5,081	3,793	4,719	4,336	5,191	4,507
Other NGLs	bbl/d	787	964	680	710	785	899	811	873	1,092	918
Natural gas(1)	mcf/d	23,529	27,414	21,863	20,062	23,229	23,695	26,959	30,005	32,576	28,281
Total Light Oil division	**boe/d**	**9,394**	**11,830**	**9,466**	**8,242**	**9,738**	**8,642**	**10,023**	**10,210**	**11,712**	**10,138**
Total Thermal Oil division bitumen	**bbl/d**	**24,839**	**20,231**	**17,601**	**28,315**	**22,745**	**27,761**	**25,234**	**23,748**	**27,494**	**26,058**
Total Company production	**boe/d**	**34,233**	**32,061**	**27,067**	**36,557**	**32,483**	**36,403**	**35,257**	**33,958**	**39,206**	**36,196**

(1) Comprised of 97% or greater of shale gas, with the remaining being conventional natural gas.
(2) Comprised of 98% 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 31,000 - 33,000 boe/d for 2021. Athabasca expects that approximately 77% of that production will be comprised of bitumen, 10% shale gas, 7% tight oil, 4% condensate natural gas liquids and 2% other 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.