Paramount Resources Ltd.

Paramount Resources Ltd. Announces Third Quarter 2021 Results, Updated 2021 Guidance, 2022 Capital Budget and Guidance and Increased Dividend

CALGARY, AB, Nov. 4, 2021 /CNW/ - Paramount Resources Ltd. ("Paramount" or the "Company") (TSX: POU) is pleased to announce strong third quarter 2021 financial and operating results, upwardly revised 2021 guidance and its approved 2022 capital expenditure budget that is forecast to generate approximately $455 million in free cash flow in 2022 on production of between 90,000 Boe/d and 94,000 Boe/d (46 percent liquids).(1)(2) The Company is also pleased to announce a tripling of its regular monthly dividend from $0.02 to $0.06 per class A common share ("Common Share") effective November 2021.

Q3 2021 HIGHLIGHTS

- Sales volumes averaged 82,150 Boe/d (45 percent liquids) in the third quarter of 2021.
    - Karr sales volumes averaged 39,878 Boe/d (52 percent liquids), in line with expectations.
    - Wapiti sales volumes averaged 14,651 Boe/d (62 percent liquids), approximately 4,000 Boe/d higher than in the second quarter despite a 10-day scheduled plant outage. This 38 percent increase in production was mainly the result of new production from the seven well 6-4 pad that was brought onstream in July.
    - Early production rates at the two-well Willesden Green 4-7 pad brought onstream in July are extremely encouraging. Despite being restricted by facility constraints, average gross peak 30-day production per well was 1,498 Boe/d (3.3 MMcf/d of shale gas and 948 Bbl/d of NGLs) with an average CGR of 287 Bbl/MMcf.(3)
- Cash from operating activities was $97.0 million in the third quarter. Adjusted funds flow was $148.4 million or $1.12 per basic share.(4) Free cash flow was $72.6 million.
- Third quarter capital spending totaled $68.9 million and was focused on drilling and completion activities at Karr, Wapiti and the Willesden Green Duvernay.
    - Preliminary all-in lease construction, drilling, completion, equip and tie-in (collectively "DCET") costs at the five-well Karr 5-16 East pad that was brought on production in late October 2021 averaged $6.3 million per well, approximately 15 percent lower than average DCET costs at the 5-16 West pad that was brought onstream in the fourth quarter of 2020.
    - The Company continues to achieve lower costs in its Karr and Wapiti drilling and completion programs despite emerging industry cost inflation by utilizing its wholly-owned Fox Drilling rigs and crews and securing fixed rates with certain service providers.
- Per unit operating costs continue to decrease and averaged $11.02/Boe in the third quarter of 2021, down from $11.23/Boe in the second quarter and $11.63/Boe in the first quarter. Karr operating costs averaged $9.03/Boe in the third quarter of 2021.
- Abandonment and reclamation expenditures in the third quarter totaled $6.9 million, net of $0.9 million in funding under the Alberta Site Rehabilitation Program ("ASRP").
- The Company implemented a regular monthly dividend in July and repurchased 197,500 Common Shares under its normal course issuer bid ("NCIB") in the third quarter at an average price of $13.66 per share.
- Paramount closed the sale of its non-operated Birch asset for proceeds of approximately $85 million.
- The carrying value of the Company's investments in securities at September 30, 2021 was approximately $300 million, approximately $75 million higher on a quarter over quarter basis.

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(1) "Free cash flow" is a Non-GAAP financial measure. See "Non-GAAP Financial Measures" in the Advisories section. See the "2022 Budget and Guidance" section for a description of the assumptions upon which the free cash flow forecast is based.

(2) In this press release, "liquids" refers to NGLs (including condensate) and oil combined, "natural gas" refers to conventional natural gas and shale gas combined, "condensate and oil" refers to condensate, light and medium crude oil and tight oil combined and "other NGLs" refers to ethane, propane and butane combined. See the Product Type Information section for a complete breakdown of sales volumes for applicable periods by the specific product types of shale gas, conventional natural gas, NGLs, tight oil and light and medium crude oil. See also "Oil and Gas

Measures and Definitions" in the Advisories section.

(3) Production measured at the wellhead. Natural gas sales volumes are lower by approximately 4% and liquids sales volumes are lower by approximately 9% due to shrinkage. Excludes days when the wells did not produce. The production rates and volumes stated are over a short period of time and, therefore, are not necessarily indicative of average daily production, long-term performance or of ultimate recovery from the wells. CGR means condensate to gas ratio and is calculated by dividing raw wellhead liquids volumes by raw wellhead natural gas volumes. See "Oil and Gas Measures and Definitions" in the Advisories section.

(4) "Adjusted funds flow" is a Non-GAAP financial measure. See "Non-GAAP Financial Measures" in the Advisories section.

UPDATED 2021 GUIDANCE

- Paramount expects fourth quarter sales volumes to range between 85,000 Boe/d and 86,500 Boe/d (45 percent liquids). As a result, full year 2021 sales volumes are expected to average approximately 82,000 Boe/d (44 percent liquids), achieving the high end of the previous guidance range of 80,000 Boe/d to 82,000 Boe/d, 1,000 Boe/d higher than the mid-point.
- The Company has added approximately $15 million of capital expenditures in the second half of 2021, which include additional activities at Wapiti to accelerate the achievement of targeted plateau production of 30,000 Boe/d into 2023 and further debottlenecking initiatives at Karr. Full year 2021 capital spending is now expected to be between $285 and $295 million.
- Paramount is forecasting 2021 free cash flow of approximately $215 million, an increase of $30 million from previous guidance. The increase reflects year-to-date actual results, updated sales volumes guidance and revised commodity price and other assumptions for the fourth quarter of 2021.[1]
- Year-end net debt to adjusted funds flow is forecast to be approximately 0.8x, below the Company's previously targeted range of 1.0x to 2.0x.[2]

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(1) The stated forecast is based on the following assumptions for 2021: (i) the midpoint of forecast capital spending and production, (ii) $25 million in net abandonment and reclamation costs, (iii) realized pricing of $47.55/Boe (US$67.63/Bbl WTI, US$3.94/MMBtu NYMEX, $3.59/GJ AECO), (iv) royalties of $4.60/Boe, (v) operating costs of $11.15/Boe and (vi) transportation and processing costs of $4.00/Boe.

(2) "Net debt" and "Net debt to adjusted funds flow" are Non-GAAP financial measures. See "Non-GAAP Financial Measures" in the Advisories section. The forecast of year end net debt to adjusted funds flow assumes the payment of a regular monthly dividend of $0.06 per Common Share commencing in November 2021 and the conversion of the Company's $35 million of convertible debentures into Common Shares in the fourth quarter of 2021.

2022 BUDGET AND GUIDANCE

The Company's 2022 capital budget is expected to range between $500 million and $540 million, excluding land acquisitions and abandonment and reclamation activities, an increase of $165 million at midpoint from preliminary guidance. The budget includes the acceleration of approximately $70 million in activities at Wapiti, $60 million to advance a number of high return opportunities in the Kaybob and Central Alberta & Other Regions and additional growth capital that will primarily benefit 2023 production. Paramount remains committed to prudently managing its capital resources and has the flexibility to adjust its capital expenditure plans depending on commodity prices and other factors.

Annual average sales volumes in 2022 are now expected to be between 90,000 Boe/d and 94,000 Boe/d (46 percent liquids), an increase of 6,000 Boe/d from previous preliminary guidance.

- First half 2022 sales volumes are expected to average between 81,000 Boe/d and 85,000 Boe/d (44 percent liquids) after accounting for a planned 16-day full field outage at Karr for turnaround activities at third-party midstream facilities.
- Second half 2022 sales volumes are expected to average between 99,000 Boe/d and 103,000 Boe/d (47 percent liquids) as numerous wells are brought onstream related to capital activities initiated earlier in 2022.

Paramount is forecasting approximately $455 million of free cash flow in 2022, $135 million higher than the Company's prior preliminary guidance.[1]

The 2022 capital budget is broken down as follows at midpoint:

- $290 million of sustaining capital and maintenance activities;
- $160 million of growth capital associated with production benefits in 2022; and
- $70 million of growth capital associated with production benefits largely in 2023.

The breakdown by region is as follows at midpoint:

- Grande Prairie − $365 million;
- Kaybob − $130 million;
- Central Alberta & Other − $10 million; and
- Corporate − $15 million

The Company has budgeted approximately $41 million for abandonment and reclamation activities in 2022. Approximately $8 million is to be funded directly through the ASRP, resulting in approximately $33 million net to Paramount. The majority of these funds will be directed to the Zama area.

(1) The stated free cash flow forecast is based on the following assumptions for 2022: (i) the midpoint of forecast capital spending and production, (ii) $33 million in net abandonment and reclamation costs, (iii) realized pricing of $53.70/Boe (US$74.44/Bbl WTI, US$4.35/MMBtu NYMEX, $3.95/GJ AECO), (iv) royalties of $6.65/Boe, (v) operating costs of $11.00/Boe and (vi) transportation and processing costs of $3.85/Boe.

FREE CASH FLOW PRIORITIES

Paramount's free cash flow priorities continue to be (i) the achievement of targeted leverage levels, (ii) shareholder returns and (iii) incremental growth.

- With strong 2021 performance and commodity prices, the Company expects year-end 2021 net debt to adjusted funds flow will be approximately 0.8x, below the previously targeted range of 1.0x to 2.0x.
- The Company is reducing its targeted long-term leverage level to approximately $300 million in net debt. This target is expected to be achieved in the third quarter of 2022, implying a net debt to trailing 12-month adjusted funds flow ratio of less than 0.5x at the end of that quarter.(1)
- Paramount implemented a regular monthly dividend of $0.02 per share in July 2021 and is tripling its monthly dividend beginning in November 2021 to $0.06 per share, implying a 10 percent payout ratio for 2022 and a 3.5 percent current dividend yield.(2)
- Remaining 2022 free cash flow will be available to:
  - further augment shareholder returns through increases in the regular monthly dividend, special dividends or opportunistic repurchases of Common Shares under the NCIB; and
  - reinvest in incremental organic growth or strategic acquisitions.

Paramount has hedged approximately 23 percent of its 2022 midpoint forecast production to provide greater free cash flow certainty. With these hedges, the Company's 2022 capital program, targeted net debt reduction and $0.06 per share regular monthly dividend would remain fully funded down to an annual average WTI price in 2022 of approximately US$52.50/Bbl with no changes to the Company's natural gas pricing assumptions.

PRELIMINARY 2023 GUIDANCE

Based on preliminary planning and current market conditions, Paramount anticipates 2023 capital spending, excluding land acquisitions and abandonment and reclamation activities, to range between $475 million and $525 million, broken down as follows at midpoint:

- $330 million of sustaining capital and maintenance activities; and
- $170 million of growth capital.

The breakdown by region is as follows at midpoint:

- Grande Prairie − $295 million;

- Kaybob − $170 million;
- Central Alberta & Other − $25 million; and
- Corporate − $10 million.

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(1) The forecasted timing of achieving the targeted net debt level and net debt to adjusted funds flow assumes the payment of a regular monthly dividend of $0.06 per Common Share commencing in November 2021 and the conversion of the Company's $35 million of convertible debentures into Common Shares in the fourth quarter of 2021.

(2) Payout ratio is calculated as total annual dividends assuming a $0.06 per Common Share regular monthly dividend divided by forecast 2022 midpoint adjusted funds flow.

A capital program in this range would be expected to result in 2023 annual average sales volumes of between 97,500 Boe/d and 102,500 Boe/d (48 percent liquids) and free cash flow of approximately $450 million.(1)

FIVE-YEAR OUTLOOK

To highlight Paramount's free cash flow and production growth potential, the Company is providing an initial five-year outlook through to the end of 2026. At current strip prices and subject to change as conditions evolve, the Company anticipates:

- annual capital spending, excluding land acquisitions and abandonment and reclamation activities, of approximately $500 million;
- a compound annual production growth rate of approximately 5 percent; and
- cumulative free cash flow of over $2.7 billion.(2)

Paramount had total tax pools of approximately $4.7 billion as of September 30, 2021, including approximately $3.5 billion of immediately deductible non-capital loss and SR&ED pools. At current strip prices, the Company does not expect to pay Canadian income taxes within the next five years.

INCREASED DIVIDEND

Paramount's Board of Directors has approved an increase in the Company's regular monthly dividend from $0.02 to $0.06 per Common Share. The first increased dividend will be payable on November 30, 2021 to shareholders of record on November 15, 2021. The dividend will be designated as an "eligible dividend" for Canadian income tax purposes.

REDEMPTION OF CONVERTIBLE DEBENTURES

The Company has delivered notices to redeem all $35 million of its 7.5% senior unsecured convertible debentures, effective December 3, 2021. It is expected that all holders will exercise their right to convert their debentures into Common Shares prior to the redemption date, resulting in approximately 5.3 million Common Shares being issued.

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(1) The free cash flow estimate is based on the following assumptions for 2023: (i) the midpoint of expected capital spending and production, (ii) $40 million in abandonment and reclamation costs, (iii) realized pricing of $48.55/Boe (US$67.39/Bbl WTI, US$3.56/MMBtu NYMEX, $3.28/GJ AECO), (iv) royalties of $5.95/Boe, (v) operating costs of $10.50/Boe and (vi) transportation and processing costs of $3.70/Boe.

(2) The stated anticipated cumulative free cash flow is based on the following assumptions: (i) the stated annual capital expenditures and compound annual production growth; (ii) approximately $40 million in average annual abandonment and reclamation costs, (iii) strip commodity prices and foreign exchange rates as at October 22, 2021, and (iv) internal management estimates of future royalties, operating costs and transportation and processing costs.

HEDGING

The Company's current hedging position is summarized below.

	Type (1)	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Average Price (2)

Oil – WTI Swaps (Sale) (Bbl/d)	Financial	10,000	–	–	–	–	US$45.82/Bbl
Oil – WTI Swaps (Sale) (Bbl/d)	Financial	–	3,500	3,500	3,500	3,500	US$75.79/Bbl
Oil – WTI Swaps (Sale) (Bbl/d)	Financial	6,000	–	–	–	–	CDN$88.45/Bbl
Oil – WTI Swaps (Sale) (Bbl/d)	Financial	–	9,500	–	–	–	CDN$87.90/Bbl
Oil – WTI Swaps (Sale) (Bbl/d)	Financial	–	–	3,500	3,500	3,500	CDN$91.38/Bbl
Oil – WTI Costless Collars (Bbl/d)	Financial	–	7,000	7,000	7,000	7,000	CDN$82.50/Bbl (Floor) CDN$100.47/Bbl (Ceiling)
Condensate – Basis (Sale) (Bbl/d)	Physical	855	2,098	–	–	–	WTI + US$3.13/Bbl
Gas – NYMEX Swaps (Sale) (MMbtu/d)	Financial	110,000	–	–	–	–	US$3.37/MMbtu
Gas – NYMEX Swaps (Sale) (MMbtu/d)	Financial	–	40,000	–	–	–	US$4.15/MMbtu
Gas – AECO fixed price (GJ/d)	Physical	116,848	–	–	–	–	CDN$3.16/GJ
Gas – AECO fixed price (GJ/d)	Physical	–	40,000	–	–	–	CDN$4.06/GJ
Gas – AECO fixed price (GJ/d)	Physical	–	–	30,000	30,000	10,109	CDN$3.54/GJ

(1) Financial, refers to financial commodity contracts. Physical, refers to fixed-priced and basis physical contracts.
(2) Average price is calculated using a weighted average of notional volumes and prices.

REVIEW OF OPERATIONS

GRANDE PRAIRIE REGION

Grande Prairie Region sales volumes and netbacks are summarized below:[1]

		Q3 2021		Q2 2021	*% Change*
Sales volumes					
Natural gas (MMcf/d)		**148.0**		134.3	*10*
Condensate and oil (Bbl/d)		**26,648**		24,090	*11*
Other NGLs (Bbl/d)		**3,274**		2,874	*14*
Total (Boe/d)		**54,586**		49,345	*11*
% liquids		***55%***		*55%*	
Netback	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	*% Change in $ millions*
Petroleum and natural gas sales	**275.8**	***54.92***	217.7	*48.47*	*27*
Royalties	**(20.5)**	***(4.08)***	(15.3)	*(3.40)*	*34*
Operating expense	**(52.6)**	***(10.47)***	(48.8)	*(10.88)*	*8*
Transportation and NGLs processing	**(22.5)**	***(4.48)***	(21.4)	*(4.76)*	5
	180.2	***35.89***	132.2	*29.43*	*36*

(1) "Netback" is a Non-GAAP financial measure. See "Non-GAAP Financial Measures" in the Advisories section.

KARR AREA

Karr sales volumes and netbacks are summarized below:

		Q3 2021		Q2 2021	% Change
Sales volumes					
Natural gas (MMcf/d)		**114.4**		107.6	*6*
Condensate and oil (Bbl/d)		**18,328**		18,458	*(1)*
Other NGLs (Bbl/d)		**2,477**		2,281	*9*
Total (Boe/d)		**39,878**		38,679	*3*
% liquids		***52%***		*54%*	
Netback	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	*% Change in $ millions*
Petroleum and natural gas sales	**195.3**	***53.23***	168.0	*47.72*	*16*
Royalties	**(17.1)**	***(4.66)***	(13.1)	*(3.72)*	*31*
Operating expense	**(33.1)**	***(9.03)***	(33.1)	*(9.40)*	-
Transportation and NGLs processing	**(15.7)**	***(4.27)***	(16.0)	*(4.52)*	*(2)*
	129.4	***35.27***	105.8	*30.08*	*22*

Third quarter sales volumes at Karr averaged 39,878 Boe/d (52 percent liquids) compared to 38,679 Boe/d (54 percent liquids) in the second quarter. Plateau production of approximately 40,000 Boe/d that was first achieved in March has been sustained through efficient and reliable operations, continued strong performance from the six-well 3-10 pad that first produced in February and new well production from the five-well 7-18 pad that came onstream in late-July. The Company continues to seek efficiencies in its operations while maintaining its focus on safety, asset integrity, reliability and environmental performance.

The 7-18 pad has outperformed internal type well projections, averaging gross peak 30-day production per well of 2,137 Boe/d (6.4 MMcf/d of shale gas and 1,076 Bbl/d of NGLs) with an average CGR of 169 Bbl/MMcf.[(1)] The Company projects that this pad will achieve payout approximately five months after coming onstream.

While remaining sharply focused on maintaining well performance, Paramount continues to realize lower than historical DCET costs despite experiencing certain inflationary pressures. Preliminary DCET costs at the five-well Karr 5-16 East pad that was brought on production in late-October 2021 averaged $6.3 million per well, approximately 15 percent lower than average DCET costs of the 5-16 West pad that was brought onstream in the fourth quarter of 2020. Drilling operations are ongoing at the twelve-well 16-17 pad and the Company expects that seven of the twelve wells will be drilled by year-end. The 16-17 pad was initially planned as a ten well pad, but two additional wells were added prior to the commencement of drilling.

Karr unit operating costs trended lower in the third quarter as a result of higher production volumes and the Company's continued focus on capturing efficiencies and streamlining operations. Paramount achieved operating costs at Karr of $9.03/Boe in the third quarter of 2021, lower than targeted operating costs of$10.00/Boe at plateau production of approximately 40,000 Boe/d. The Company also achieved a record netback of $35.27/Boe at Karr in the third quarter.

In 2022, Paramount plans to maintain plateau production at Karr of 40,000 Boe/d by drilling 14 Montney wells and bringing onstream 16 wells, consistent with the Company's expectation that a total of 12 to 16 new wells per year are needed to maintain plateau production. The twelve-well 16-17 pad is currently being drilled and will be brought on production in two phases, with the first seven wells scheduled to come onstream in the second quarter of 2022 and the remaining five wells to come onstream in the second half of the year. Drilling of the four-well 1-2 North pad is scheduled to commence in the second quarter and the Company plans to bring all four wells onstream in late-2022. The Company also plans to bring onstream additional gas lift compression in the year to support liquids production as well as build out certain infrastructure to debottleneck future production.

(1) Production measured at the wellhead. Natural gas sales volumes are lower by approximately 6% and liquids sales volumes are lower by approximately 6% due to shrinkage. Excludes days when the wells did not produce. The production rates and volumes stated are over a short period of time and, therefore, are not necessarily indicative of average daily production, long-term performance or of ultimate recovery from the wells. CGR means condensate to gas ratio and is calculated by dividing raw wellhead liquids volumes by raw wellhead natural gas volumes. See "Oil and Gas Measures and Definitions" in the Advisories section.

WAPITI AREA

Wapiti sales volumes and netbacks are summarized below:

	Q3 2021		Q2 2021		*% Change*
Sales volumes					
Natural gas (MMcf/d)		**33.3**		26.4	*26*
Condensate and oil (Bbl/d)		**8,310**		5,629	*48*
Other NGLs (Bbl/d)		**790**		582	*36*
Total (Boe/d)		**14,651**		10,604	*38*
% liquids		***62%***		*59%*	
Netback	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	*% Change in $ millions*
Petroleum and natural gas sales	**80.4**	***59.62***	49.6	*51.41*	*62*
Royalties	**(3.4)**	***(2.49)***	(2.1)	*(2.24)*	*62*
Operating expense	**(19.2)**	***(14.25)***	(15.4)	*(16.00)*	*25*
Transportation and NGLs processing	**(6.9)**	***(5.09)***	(5.5)	*(5.65)*	*25*
	50.9	***37.79***	26.6	*27.52*	*91*

Third quarter sales volumes at Wapiti averaged 14,651 Boe/d (62 percent liquids) compared to 10,604 Boe/d (59 percent liquids) in the second quarter due to new well production from the seven-well 6-4 pad that was brought onstream in July. Gross peak 30-day production per well from the 6-4 pad averaged 1,292 Boe/d (3.0 MMcf/d of shale gas and 794 Bbl/d of NGLs) with an average CGR of 266 Bbl/MMcf.[1] Third quarter production was impacted by the previously disclosed scheduled ten-day outage at the third-party Wapiti natural gas processing facility.

Drilling operations at the seven-well 9-22 pad are now complete, with four of the seven wells having been configured as monobores. Compared with conventional multiple casing wellbores, monobore wells require less steel in the form of casing and less time on lease installing and cementing the additional casing, resulting in lower capital costs. Additional cost and well productivity benefits are also anticipated due to higher pumping rates afforded by the larger diameter wellbore. The Company plans to complete, tie-in and bring onstream four wells in December with the remaining three wells to be brought onstream in the first quarter of 2022.

As a result of capital cost savings achieved to date in 2021 and in support of reaching plateau production of 30,000 Boe/d at Wapiti in 2023, Paramount is accelerating the commencement of drilling operations of the eight-well 8-22 pad into 2021.

In 2022, the Company plans to grow Wapiti production to approximately 27,000 Boe/d by year end by drilling 32 wells and bringing onstream a total of 22 wells. Drilling, completion and tie-in activities at the eight-well 8-22 pad are scheduled to commence in late-2021 and continue through the first half of 2022, with the majority of the wells to be brought onstream in the second quarter of 2022. Paramount plans to drill, complete and tie-in two additional eight-well pads, at 6-32 and 16-15, with drilling scheduled for the second and third quarters of 2022 respectively. The 6-32 pad is expected to be onstream in the second half of 2022 while the majority of the 16-15 pad wells will be brought onstream in early 2023. Drilling of the eight-well 8-15 pad is scheduled for late 2022. The Company also plans to complete a tenure well in 2022.

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(1) Production measured at the wellhead. Natural gas sales volumes are lower by approximately 13% and liquids sales volumes are lower by approximately 1% due to shrinkage. Excludes days when the wells did not produce. The production rates and volumes stated are over a short period of time and, therefore, are not necessarily indicative of average daily production, long-term performance or of ultimate recovery from the wells. CGR means condensate to gas ratio and is calculated by dividing raw wellhead liquids volumes by raw wellhead natural gas volumes. See Oil and Gas Measures and Definitions in the Advisories section.

KAYBOB REGION

Kaybob Region sales volumes averaged 21,054 Boe/d (28 percent liquids) in the third quarter of 2021 compared to 22,688 Boe/d (28 percent liquids) in the second quarter. The decrease in production is largely attributable to natural declines.

In 2022, Paramount plans to pursue the development of its Duvernay assets at Kaybob North and Kaybob Smoky. At

Kaybob North, the Company plans to drill the remaining two wells at the three-well 12-21 pad and bring all three wells onstream in the second half of 2022. At Kaybob Smoky, plans include the expansion of the Company's 100% owned and operated 6-16 facility and the drilling, completion, tie-in and bringing onstream of the four-well 10-35 pad, also in the second half of 2022.

The Company expects to realize capital cost efficiencies in its Kaybob Duvernay plays, similar to those achieved over the past two years at Karr and Wapiti, as it commences pad development and captures economies of scale.

The Company plans to pursue other high return opportunities at Kaybob in 2022, including bringing onstream four Montney gas wells, two Montney oil wells and two Gething oil wells, seven of which will be drilled in 2022. Other activities include an expansion of the enhanced oil recovery scheme at the Company's Kaybob Montney Oil property.

CENTRAL ALBERTA & OTHER REGION

Central Alberta & Other Region sales volumes averaged 6,510 Boe/d (22 percent liquids) in the third quarter of 2021 compared to 7,962 Boe/d (13 percent liquids) in the second quarter. Sales volumes in the third quarter decreased primarily due to the sale of the non-operated Birch assets in July and, to a lesser extent, a third-party pipeline outage and natural declines. New well production from the two-well Willesden Green Duvernay 4-7 pad that was brought on production in July partially offset these decreases. Despite being restricted by facility constraints, average gross peak 30-day production per well at the 4-7 pad was 1,498 Boe/d (3.3 MMcf/d of shale gas and 948 Bbl/d of NGLs) with an average CGR of 287 Bbl/MMcf.

The Company holds a material, contiguous Duvernay position at Willesden Green and continues to actively evaluate longer-term full field development plans for this asset. Material learnings from the drilling of the two wells at the 4-7 pad, particularly in drilling long reach laterals in the Duvernay formation, have resulted in further optimization to pad layouts in the full field development plans across the Company's Duvernay lands, improving economics. DCET costs at the 4-7 pad averaged $11.3 million per well. The Company anticipates reductions in average well costs once commercial scale development commences and critical infrastructure is in place.

In 2022, planned activities include the addition of water infrastructure and FEED studies for future facility expansion that will benefit Duvernay development in the Willesden Green area.

ABOUT PARAMOUNT

Paramount is an independent, publicly traded, liquids-focused Canadian energy company that explores for and develops both conventional and unconventional petroleum and natural gas reserves and resources, including longer-term strategic exploration and pre-development plays, and holds a portfolio of investments in other entities. The Company's principal properties are located in Alberta and British Columbia. Paramount's class A common shares are listed on the Toronto Stock Exchange under the symbol "POU".

Paramount's third quarter 2021 results, including Management's Discussion and Analysis and the Company's Consolidated Financial Statements can be obtained at:
https://mma.prnewswire.com/media/1678630/Paramount_Resources_Ltd__Paramount_Resources_Ltd__Announces_Thir.pdf

A summary of historical financial and operating results is also available on Paramount's website at https://www.paramountres.com/investors/financial-shareholder-reports.

This information will also be made available through Paramount's website at www.paramountres.com and on SEDAR at www.sedar.com.

FINANCIAL AND OPERATING RESULTS[1] ($ millions, except as noted)	**Q3 2021**	**Q2 2021**
Net income (loss)	**292.7**	(74.3)
per share – basic ($/share)	***2.20***	*(0.56)*
per share – diluted ($/share)	***2.06***	*(0.56)*
Cash from operating activities	**97.0**	112.1
per share – basic ($/share)	***0.73***	*0.84*
per share – diluted ($/share)	***0.68***	*0.84*

Adjusted funds flow	**148.4**		86.0	
per share – basic ($/share)	***1.12***		*0.65*	
per share – diluted ($/share)	***1.04***		*0.65*	
Total assets	**3,882.9**		3,655.6	
Long-term debt	**522.4**		608.4	
Net debt	**576.8**		724.5	
Common shares outstanding *(thousands)* (2)	**133,207**		133,314	
Sales volumes				
Natural gas (MMcf/d)	**269.7**		273.1	
Condensate and oil (Bbl/d)	**32,177**		29,543	
Other NGLs (Bbl/d) (3)	**5,017**		4,938	
Total (Boe/d)	**82,150**		79,995	
% liquids	***45%***		*43%*	
Grande Prairie Region (Boe/d)	**54,586**		49,345	
Kaybob Region (Boe/d)	**21,054**		22,688	
Central Alberta & Other Region (Boe/d)	**6,510**		7,962	
Total (Boe/d)	**82,150**		79,995	
Netback		*$/Boe* (3)		*$/Boe* (3)
Natural gas revenue	**96.5**	***3.89***	74.8	*3.01*
Condensate and oil revenue	**249.9**	***84.42***	209.6	*77.96*
Other NGLs revenue	**21.7**	***47.05***	14.4	*32.11*
Royalty and other revenue	**1.0**	**—**	0.9	—
Petroleum and natural gas sales	**369.1**	***48.84***	299.7	*41.17*
Royalties	**(30.9)**	***(4.09)***	(24.9)	*(3.43)*
Operating expense	**(83.3)**	***(11.02)***	(81.8)	*(11.23)*
Transportation and NGLs processing (4)	**(30.3)**	***(4.01)***	(30.3)	*(4.16)*
Netback	**224.6**	***29.72***	162.7	*22.35*
Financial commodity contract settlements	**(59.0)**	***(7.81)***	(54.1)	*(7.44)*
		21.91		*14.91*
Netback including financial commodity contract settlements	**165.6**		108.6	
Total Capital Expenditures				
Grande Prairie Region	**53.1**		66.5	
Kaybob Region	**1.7**		3.9	
Central Alberta & Other Region	**9.7**		11.8	
Corporate (5)	**1.6**		1.2	
Land acquisitions	**2.8**		0.1	
Total capital expenditures	**68.9**		83.5	
Asset retirement obligation settlements	**6.9**		3.2	

(1) Readers are referred to the advisories concerning Non-GAAP Financial Measures and Oil and Gas Measures and Definitions in the Advisories section of this document. This table contains the following Non-GAAP financial measures: Adjusted funds flow, Net debt, Netback and Total capital expenditures. Readers are referred to the Product Type Information section of this document for a complete breakdown of sales volumes for applicable periods by the specific product types.

(2) Presented net of shares held in trust under the Company's restricted share unit plan (000's of common shares): Q3 2021: 1,536 and Q2 2021: 1,538.

(3) Natural gas revenue presented as $/Mcf.

(4) Includes downstream transportation costs and NGLs fractionation costs.

(5) Includes transfers between regions.

PRODUCT TYPE INFORMATION

This press release refers to sales volumes of "natural gas", "condensate and oil", "NGLs", "Other NGLs" and "Liquids". "Natural gas" refers to conventional natural gas and shale gas combined. "Condensate and oil" refers to condensate, light and medium crude oil and tight oil combined. "NGLs" refers to condensate and Other NGLs combined. "Other NGLs" refers to ethane, propane and butane combined. "Liquids" refers to condensate and oil and Other NGLs combined. Below is a complete breakdown of sales volumes for applicable periods by the specific product types of shale gas, conventional natural gas, NGLs, tight oil and light and medium crude oil. Numbers may not add due to rounding.

	Total		Grande Prairie Region		Kaybob Region		Central Alberta & Other Region	
	Q3 2021	Q2 2021	Q3 2021	Q2 2021	Q3 2021	Q2 2021	Q3 2021	Q2 2021
Shale gas (MMcf/d)	**207.1**	205.8	**145.8**	132.2	**36.9**	39.3	**24.4**	34.3
Conventional natural gas (MMcf/d)	**62.6**	67.3	**2.2**	2.1	**54.4**	58.0	**6.0**	7.2
Natural gas (MMcf/d)	**269.7**	273.1	**148.0**	134.3	**91.3**	97.3	**30.4**	41.5
Condensate (Bbl/d)	**29,670**	26,784	**26,639**	24,086	**2,072**	2,319	**959**	379
Other NGLs (Bbl/d)	**5,017**	4,938	**3,274**	2,874	**1,415**	1,569	**328**	495
NGLs (Bbl/d)	**34,687**	31,722	**29,913**	26,960	**3,487**	3,888	**1,287**	874
Tight oil (Bbl/d)	**475**	494	**–**	–	**368**	354	**107**	140
Light and medium crude oil (Bbl/d)	**2,032**	2,265	**9**	4	**1,979**	2,224	**44**	37
Crude oil (Bbl/d)	**2,507**	2,759	**9**	4	**2,347**	2,578	**151**	177
Total (Boe/d)	**82,150**	79,995	**54,586**	49,345	**21,054**	22,688	**6,510**	7,962

	Karr		Wapiti	
	Q3 2021	Q2 2021	Q3 2021	Q2 2021
Shale gas (MMcf/d)	**113.0**	106.3	**32.7**	25.9
Conventional natural gas (MMcf/d)	**1.4**	1.3	**0.6**	0.5
Natural gas (MMcf/d)	**114.4**	107.6	**33.3**	26.4
NGLs (Bbl/d)	**20,805**	20,739	**9,100**	6,211
Total (Boe/d)	**39,878**	38,679	**14,651**	10,604

The Company forecasts that fourth quarter 2021 sales volumes will average between 85,000 Boe/d and 86,500 Boe/d (55 percent shale gas and conventional natural gas combined, 39 percent light and medium crude oil, tight oil and condensate combined and 6 percent other NGLs).

The Company forecasts that 2021 annual sales volumes will average approximately 82,000 Boe/d (56 percent shale gas and conventional natural gas combined, 38 percent light and medium crude oil, tight oil and condensate combined and 6 percent other NGLs).

The Company forecasts that 2022 sales volumes will average between 90,000 Boe/d and 94,000 Boe/d (54 percent shale gas and conventional natural gas combined, 40 percent light and medium crude oil, tight oil and condensate combined and 6 percent other NGLs). First half 2022 sales volumes are expected to average between 81,000 Boe/d and 85,000 Boe/d (56 percent shale gas and conventional natural gas combined, 38 percent light and medium crude oil, tight oil and condensate combined and 6 percent other NGLs). Second half 2022 sales volumes are expected to average between 99,000 Boe/d and 103,000 Boe/d (53 percent shale gas and conventional natural gas combined, 41 percent light and medium crude oil, tight oil and condensate combined and 6 percent other NGLs).

ADVISORIES

Forward-looking Information

Certain statements in this press release constitute forward-looking information under applicable securities legislation. Forward-looking information typically contains statements with words such as "anticipate", "believe", "estimate", "will", "expect", "plan", "schedule", "intend", "propose", or similar words suggesting future outcomes or an outlook. Forward-looking information in this press release includes, but is not limited to:

- forecast free cash flow in 2021 and 2022;
- forecast 2021 year-end net debt to annual adjusted funds flow;

- planned capital expenditures in 2021 and 2022;
- forecast sales volumes for 2021 and 2022 and certain periods therein;
- the expectation that plateau production will be reached at Wapiti in 2023;
- the anticipated meeting by the Company of its $300 million net debt target by the end of the third quarter of 2022 and the implied net debt to adjusted funds flow ratio at the end of the third quarter of 2022;
- the Company's priorities and expectations respecting the allocation of free cash flow;
- planned abandonment and reclamation expenditures and activities in 2022;
- preliminary anticipated capital expenditures in 2023 and the resulting expected 2023 average sales volumes and free cash flow;
- the Company's five-year outlook for capital spending, annual production growth rate and cumulative free cash flow;
- the Company's expectation that it will not be required to pay Canadian income taxes within the next five years;
- the expectation that all holders will exercise their right to convert their debentures into Common Shares prior to the redemption date;
- planned exploration, development and production activities, including the expected timing of completing and bringing new wells on production;
- the expectation that a total of 12 to 16 wells per year are needed to maintain plateau production at Karr;
- preliminary estimated drilling, completion and equipping costs;
- the payment of future dividends under the Company's monthly dividend program; and
- expected capital cost efficiencies at the Company's Kaybob Duvernay properties and the expectation that average well costs at the Company's Duvernay properties will be reduced once commercial scale development commences.

Such forward-looking information is based on a number of assumptions which may prove to be incorrect. Assumptions have been made with respect to the following matters, in addition to any other assumptions identified in this press release:

- future commodity prices and the potential impact of the COVID-19 pandemic thereon;
- the likely impact of the COVID-19 pandemic on operations;
- the ability to realize expected cost savings;
- royalty rates, taxes and capital, operating, processing, transportation, general & administrative and other costs;
- foreign currency exchange rates and interest rates;
- general business, economic and market conditions;
- the performance of wells and facilities;
- the ability of Paramount to obtain the required capital to finance its exploration, development and other operations and meet its commitments and financial obligations;
- the ability of Paramount to obtain equipment, services, supplies and personnel in a timely manner and at an acceptable cost to carry out its activities;
- the ability of Paramount to secure adequate product processing, transportation, fractionation and storage capacity on acceptable terms and the capacity and reliability of facilities;
- the ability of Paramount to market its production successfully to current and new customers;
- the ability of Paramount and its industry partners to obtain drilling success (including in respect of anticipated production volumes, reserves additions, product yields and resource recoveries) and operational improvements, efficiencies and results consistent with expectations;
- the timely receipt of required governmental and regulatory approvals;
- the receipt of benefits under government programs;
- the application of regulatory requirements respecting abandonment and reclamation;
- in the case of the expectation that all holders will exercise their right to convert their debentures into Common Shares prior to the redemption date, the assumption that the trading price of the Common Shares will continue to remain substantially above the conversion price of the debentures; and
- anticipated timelines and budgets being met in respect of drilling programs and other operations (including well completions and tie-ins, the construction, commissioning and start-up of new and expanded facilities, including third-party facilities, and facility turnarounds and maintenance).

In addition to the above, the Company's expectation to not pay Canadian income taxes within the next five years is based on the current tax regime, the Company's tax pools and the assumptions with respect to production, expenditures, commodity prices, royalties and costs in the five years ended 2026 set forth herein. Taxable income varies depending on total income and expenses and Paramount's estimate is sensitive to assumptions regarding commodity prices, production, cash from operating activities, capital spending levels and acquisition and disposition transactions. Changes in these factors could result in the Company paying income taxes earlier than expected.

Although Paramount believes that the expectations reflected in such forward-looking information are reasonable based on the information available at the time of this press release, undue reliance should not be placed on the forward-looking information as Paramount can give no assurance that such expectations will prove to be correct. Forward-looking information is based on expectations, estimates and projections that involve a number of risks and uncertainties which could cause actual results to differ materially from those anticipated by Paramount and described in the forward-looking information. The material risks and uncertainties include, but are not limited to:

- fluctuations in commodity prices, including in relation to the impact of the COVID-19 pandemic;
- changes in capital spending plans and planned exploration and development activities;
- the potential for changes to preliminary anticipated 2023 capital expenditures prior to finalization and changes to the resulting expected 2023 average sales volumes and free cash flow;
- the potential for changes to the Company's five-year outlook for capital spending, annual production growth rate and cumulative free cash flow;
- changes in foreign currency exchange rates and interest rates;
- the uncertainty of estimates and projections relating to future revenue, free cash flow, production, reserves additions, product yields (including condensate to natural gas ratios), resource recoveries, royalty rates, taxes and costs and expenses;
- the ability to secure adequate product processing, transportation, fractionation, and storage capacity on acceptable terms;
- operational risks in exploring for, developing, producing and transporting natural gas and liquids, including the risk of spills, leaks or blowouts;
- the ability to obtain equipment, services, supplies and personnel in a timely manner and at an acceptable cost;
- potential disruptions, delays or unexpected technical or other difficulties in designing, developing, expanding or operating new, expanded or existing facilities (including third-party facilities);
- processing, pipeline, and fractionation infrastructure outages, disruptions and constraints;
- risks and uncertainties involving the geology of oil and gas deposits;
- the uncertainty of reserves estimates;
- general business, economic and market conditions;
- the ability to generate sufficient cash from operating activities and obtain financing to fund planned exploration, development and operational activities and meet current and future commitments and obligations (including product processing, transportation, fractionation and similar commitments and obligations);
- changes in, or in the interpretation of, laws, regulations or policies (including environmental laws);
- the ability to obtain required governmental or regulatory approvals in a timely manner, and to enter into and maintain leases and licenses;
- the effects of weather and other factors including wildlife and environmental restrictions which affect field operations and access;
- the timing and cost of future abandonment and reclamation obligations and potential liabilities for environmental damage and contamination;
- uncertainties regarding aboriginal claims and in maintaining relationships with local populations and other stakeholders;
- the outcome of existing and potential lawsuits, insurance claims, regulatory actions, audits and assessments; and
- other risks and uncertainties described elsewhere in this document and in Paramount's other filings with Canadian securities authorities.

There are risks that may result in the Company changing, suspending or discontinuing its monthly dividend program, including changes to free cash flow, operating results, capital requirements, financial position, market conditions or corporate strategy and the need to comply with requirements under debt agreements and applicable laws respecting the declaration and payment of dividends. There are no assurances as to the continuing declaration and payment of future dividends under the Company's monthly dividend program or the amount or timing of any such dividends.

The foregoing list of risks is not exhaustive. For more information relating to risks, see the sections titled "*Risk Factors*" in Paramount's annual information form for the year ended December 31, 2020, which is available on SEDAR at www.sedar.com. The forward-looking information contained in this press release is made as of the date hereof and, except as required by applicable securities law, Paramount undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise.

Certain forward-looking information in this press release, including forecast free cash flow in 2021, 2022 and future periods and forecast 2021 and 2022 net debt to annual adjusted funds flow ratios, may also constitute a "financial outlook" within the meaning of applicable securities laws. A financial outlook involves statements about Paramount's prospective financial performance or position and is based on and subject to the assumptions and risk factors described above in respect of forward-looking information generally as well as any other specific assumptions and risk factors in relation to such financial outlook noted in this press release. Such assumptions are based on management's assessment of the relevant information currently available and any financial outlook included in this press release is provided for the purpose of helping readers understand Paramount's current expectations and plans for the future. Readers are cautioned that reliance on any financial outlook may not be appropriate for other purposes or in other circumstances and that the risk factors described above or other factors may cause actual results to differ materially from any financial outlook.

Non-GAAP Financial Measures

In this press release, "adjusted funds flow", "free cash flow", "netback", "net debt", "net debt to adjusted funds flow" and "total capital expenditures", together the "Non-GAAP financial measures", are used and do not have any standardized meanings as prescribed by International Financial Reporting Standards.

"Adjusted funds flow" refers to cash from (used in) operating activities before net changes in non-cash working capital, geological and geophysical expenses, asset retirement obligation settlements, closure costs, provisions and other, dispute settlements and transaction and reorganization costs. Adjusted funds flow is used to assist management and investors in measuring the Company's ability to fund capital programs and meet financial obligations, including the settlement of asset retirement obligations. Asset retirement obligation settlements are excluded from the calculation of adjusted funds flow because such expenditures are not directly linked to the revenue generating activities of the Company. Paramount manages the timing of expenditures related to asset retirement obligation settlements in accordance with regulatory requirements and its overall approach to managing its asset retirement obligations and, as a result, amounts incurred may vary significantly from period to period. Adjusted funds flow is not intended to represent cash from operating activities, net loss or any other GAAP measure and should not be construed as being an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with IFRS. The following are the calculations of adjusted funds flow from the nearest GAAP measure for the three months ended September 30, 2021 and June 30, 2021:

Three months ended	Sept 30, 2021 (MM$)	Jun 30, 2021 (MM$)
Cash from operating activities	**97.0**	**112.1**
Change in non-cash working capital	42.9	(47.6)
Geological and geophysical expenses	1.6	1.8
Asset retirement obligations settled	6.9	3.2
Closure costs	–	–
Provisions and other	–	16.5
Dispute settlements	–	–
Transaction and reorganization costs	–	–
Adjusted funds flow	**148.4**	**86.0**

"Free cash flow" refers to adjusted funds flow less total capital expenditures and asset retirement obligation settlements. Free cash flow is used by management and investors to assess the amount of internally generated cash available to repay debt, reinvest in the business or return to shareholders. The following is the calculation of free cash flow from the nearest GAAP measure for the three months ended September 30, 2021 and June 30, 2021:

Three months ended	Sept 30, 2021 (MM$)	Jun 30, 2021 (MM$)
Adjusted funds flow	**148.4**	**86.0**
Total capital expenditures	(68.9)	(83.5)
Asset retirement obligation settlements	(6.9)	(3.2)
Free cash flow	**72.6**	**(0.7)**

"Netback" equals petroleum and natural gas sales less royalties, operating expense and transportation and NGLs processing costs. Netback is commonly used by management and investors to compare the results of the Company's oil and gas operations between periods. Refer to the tables under the headings "Review of Operations" and "Financial and Operating Results" for the calculation thereof.

"Net debt" is a measure of the Company's overall debt position after adjusting for certain working capital and other amounts and is used by management to assess the Company's overall leverage position. Refer to the Liquidity and Capital Resources section of the Company's Management's Discussion and Analysis for the three months and nine months ended September 30, 2021 (the "MD&A") for the calculation of net debt.

"Net debt to adjusted funds flow" is a ratio calculated as the period end net debt divided by adjusted funds flow for the trailing four quarters. The ratio of net debt to adjusted funds flow is commonly used by management and investors to assess the Company's overall debt position.

"Total capital expenditures" refers to the Company's property, plant and equipment and exploration expenditures. Refer to the Total Capital Expenditures section of the MD&A for the calculation thereof.

Non-GAAP financial measures should not be considered in isolation or construed as alternatives to their most directly comparable measure calculated in accordance with GAAP, or other measures of financial performance calculated in accordance with GAAP. The Non-GAAP financial measures are unlikely to be comparable to similar measures presented by other issuers.

Oil and Gas Measures and Definitions

Abbreviations

Liquids		**Natural Gas**	
Bbl	Barrels	GJ	Gigajoules
Bbl/d	Barrels per day	GJ/d	Gigajoules per day
MBbl	Thousands of barrels	Mcf	Thousands of cubic feet
NGLs	Natural gas liquids	MMcf	Millions of cubic feet
Condensate	Pentane and heavier hydrocarbons	MMcf/d	Millions of cubic feet per day
WTI	West Texas Intermediate	AECO	AECO-C reference price
		NYMEX	New York Mercantile Exchange
		MMbtu	Millions of British thermal units
		MMbtu/d	Millions of British thermal units per day

Oil Equivalent	
Boe	Barrels of oil equivalent
MBoe	Thousands of barrels of oil equivalent
MMBoe	Millions of barrels of oil equivalent
Boe/d	Barrels of oil equivalent per day

This press release contains disclosures expressed as "Boe", "$/Boe" and "Boe/d". Natural gas equivalency volumes have been derived using the ratio of six thousand cubic feet of natural gas to one barrel of oil when converting natural gas to Boe. Equivalency measures may be misleading, particularly if used in isolation. A conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head. For the nine months ended September 30, 2021, the value ratio between crude oil and natural gas was approximately 26:1. This value ratio is significantly different from the energy equivalency ratio of 6:1. Using a 6:1 ratio would be misleading as an indication of value.

This press release refers to "CGR", a metric commonly used in the oil and natural gas industry. "CGR" means condensate to gas ratio and is calculated by dividing wellhead raw liquids volumes by wellhead raw natural gas volumes. This metric does not have a standardized meaning and may not be comparable to similar measures presented by other companies. As such, it should not be used to make comparisons. Management uses oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare the Company's performance over time; however, such measures are not reliable indicators of the Company's future performance and future performance may not compare to the performance in previous periods and therefore should not be unduly relied upon.

Additional information respecting the Company's oil and gas properties and operations is provided in the Company's annual information form for the year ended December 31, 2020 which is available on SEDAR at www.sedar.com.

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