Paramount Resources Ltd.

Paramount Resources Ltd. Reports Third Quarter 2020 Results

CALGARY, AB, Nov. 5, 2020 /CNW/ -

HIGHLIGHTS

- Sales volumes averaged 61,064 Boe/d (39 percent liquids) in the third quarter of 2020 compared to 68,839 Boe/d (39 percent liquids) in the second quarter.
    - Third quarter sales volumes at Karr averaged 19,246 Boe/d (57 percent liquids) compared to 16,009 Boe/d (52 percent liquids) in the second quarter.
    - At Wapiti, third quarter sales volumes were 7,925 Boe/d (63 percent liquids), approximately 7,000 Boe/d lower than the second quarter, due to an unplanned six-week outage at a third-party natural gas processing facility in the Wapiti field (the "Wapiti Plant"). Paramount is pursuing a claim under its contingent business interruption insurance policy related to the outage. The policy has a 30-day waiting period and recoveries are expected to exceed $5 million.
- At Karr, the five wells on the 2-1 pad were brought on production through permanent facilities in early September. Average gross peak 30-day production per well was 1,463 Boe/d, including 735 Bbl/d of wellhead liquids, with an average wellhead CGR of 168 Bbl/MMcf.(1)
- Despite lower production, Paramount's netback was $44.3 million in the third quarter of 2020 compared to $21.7 million in the second quarter of 2020, reflecting higher liquids prices.(2)
- Cash from operating activities was $11.4 million in the third quarter of 2020. Adjusted funds flow was $29.5 million or $0.22 per share.(2)
- Third quarter capital spending totaled $50.5 million, primarily related to drilling and completion activities at Karr. Spending included a portion of the previously-announced acceleration of certain activities from 2021.
- The Company continues to realize significant cost savings in its capital program through its focus on well design, increased efficiencies and lower vendor rates, while not compromising on completion effectiveness:
    - All-in lease construction, drilling, completion, equip and tie-in (collectively, "DCET") costs for the five-well (all Middle Montney) Karr 2-1 pad averaged $7.3 million per well, $0.2 million lower than prior estimates. This represents a 39 percent reduction compared with average DCET costs for Karr wells in 2018 and 2019.
    - Completion activities at the five-well (three Upper Montney and two Middle Montney) Karr 5-16 West pad have recently been concluded and preliminary lease construction, drilling and completion costs are estimated at $7.2 million per well.
    - At Wapiti, completion activities at the five-well (two Middle Montney and three Lower Montney) 5-3 West pad were recently concluded. The Company estimates preliminary lease construction, drilling and completion costs of $7.3 million per well. Despite higher fluid and proppant intensity, estimated completion costs are approximately 30 percent lower than the 2019 5-3 East pad due to improved efficiencies and optimized completion design.

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(1) Production measured at the wellhead. Natural gas sales volumes are lower by approximately 7 percent and liquids sales volumes are lower by approximately 7 percent 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. CGRs are calculated by dividing raw wellhead liquids volumes by raw wellhead natural gas volumes. See Oil and Gas Measures and Definitions in the Advisories section.

(2) "Netback" and "Adjusted funds flow" are Non-GAAP measures. See "Non-GAAP Measures" in the Advisories section.

- Paramount, in collaboration with its vendors, has received approval for up to approximately $10 million of funding under the Alberta Site Rehabilitation Program ("ASRP") to date. It is anticipated that approximately $4 million of abandonment and reclamation work under the ASRP will occur in the fourth quarter of 2020, with the remainder to be undertaken in 2021.

- The Company has completed the installation of the remaining low-bleed controllers in the Grande Prairie Region which brings the high-bleed emission reduction project to completion across the organization. In total, 1,900 high-bleed controllers have been replaced, reducing annual GHG emissions by an estimated 75,000 tonnes of carbon dioxide equivalent ("CO_2e").[1]

CORPORATE

- Paramount has now exceeded its previously announced 2020 cost reduction targets of $25 million in operating costs and $15 million in general and administrative expenses.
    - Operating costs averaged $11.10/Boe in the third quarter of 2020. Fourth quarter operating costs are now anticipated to average approximately $11.50/Boe as a result of higher fourth quarter production and the Company's continued efforts in sustainably improving its cost structure.
- The Company is maintaining its 2020 capital guidance of $225 million.
- Paramount has largely brought back production that was previously shut-in due to the deterioration of commodity prices in the second quarter.
- Paramount is increasing the mid-point of its production guidance, with sales volumes anticipated to average between 70,000 Boe/d and 72,000 Boe/d in the fourth quarter of 2020, reflecting the Company's confidence in the onstream timing of new wells.
- Long-term debt at September 30, 2020 was $792.7 million.
- Paramount has undertaken an active hedging program and in the third quarter added several additional hedges to provide greater funds flow certainty and further protect the Company's capital program. Nearly 50 percent of the Company's anticipated fourth quarter production is hedged. See below under "Hedging".

(1) Excludes GHG emissions related to certain natural gas-weighted properties that were sold in late 2019.

2021 CAPITAL PROGRAM

Paramount expects to finalize its 2021 capital budget and related guidance in the first quarter of 2021. Based on preliminary planning and current market conditions, Paramount anticipates 2021 capital spending, excluding land acquisitions and abandonment and reclamation activities, to range between $225 million and $275 million. A capital program in this range would be expected to result in:

- 2021 annual average sales volumes of between 77,500 Boe/d and 82,500 Boe/d (45% liquids); and
- adjusted funds flow that exceeds capital spending by approximately $100 million, assuming the midpoint of the capital spending and production ranges, realized pricing of $32.00/Boe, operating costs of $11.25/Boe and transportation and processing costs of $4.00/Boe.

REVIEW OF OPERATIONS

<u>GRANDE PRAIRIE REGION</u>

Grande Prairie Region sales volumes and netbacks are summarized below:

	Q3 2020	Q2 2020	*% Change*
Sales volumes			
Natural gas (MMcf/d)	**67.3**	78.3	*(14)*
Condensate and oil (Bbl/d)	**13,960**	16,309	*(14)*
Other NGLs (Bbl/d)	**2,060**	1,680	*23*
Total (Boe/d)	**27,237**	31,039	*(12)*
% liquids	***59%***	*58%*	

Netback	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	*% Change in $ millions*
Petroleum and natural gas sales	**79.1**	***31.58***	60.3	*21.34*	*31*
Royalties [1]	**(2.2)**	***(0.90)***	0.3	*0.12*	*NM*
Operating expense	**(38.8)**	***(15.47)***	(38.8)	*(13.73)*	*-*
Transportation and NGLs processing	**(15.6)**	***(6.23)***	(12.9)	*(4.58)*	*21*

	22.5	***8.98***	8.9	*3.15*	*153*

[1] Second quarter royalties were impacted by lower prices and adjustments related to prior year gas cost allowance.
NM means not meaningful

Karr

Karr sales volumes and netbacks are summarized below:

	Q3 2020	Q2 2020	*% Change*
Sales volumes			
Natural gas (MMcf/d)	**49.2**	46.1	*7*
Condensate and oil (Bbl/d)	**9,541**	7,501	*27*
Other NGLs (Bbl/d)	**1,503**	829	*81*
Total (Boe/d)	**19,246**	16,009	*20*
% liquids	***57%***	*52%*	

Netback	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	*% Change in $ millions*
Petroleum and natural gas sales	**54.9**	***31.01***	29.4	*20.20*	*87*
Royalties [1]	**(1.4)**	***(0.80)***	1.3	*0.87*	*NM*
Operating expense	**(26.2)**	***(14.77)***	(22.4)	*(15.39)*	*17*
Transportation and NGLs processing	**(10.9)**	***(6.17)***	(7.2)	*(4.91)*	*51*
	16.4	***9.27***	1.1	*0.77*	*NM*

[1] Second quarter royalties were impacted by lower prices and adjustments related to prior year gas cost allowance.
NM means not meaningful

Third quarter sales volumes at Karr averaged 19,246 Boe/d (57 percent liquids) compared to 16,009 Boe/d (52 percent liquids) in the second quarter. Sales volumes were higher primarily due to production contributions from the 12-18 pad that first flowed through test facilities in the second quarter and was subsequently brought onstream through permanent facilities in early July, as well as the 2-1 pad that was brought onstream through permanent facilities in early September. Sales volumes also benefited from a pipeline debottlenecking project designed to mitigate current and potential future back-out issues as new pads are brought on production. The project included the installation of booster pumps servicing the southwest extents of the Karr gathering system and has resulted in improved runtime of both legacy and new wells in the area.

Per unit operating costs continue to trend lower as a result of increasing volumes combined with the impact of two water disposal wells that were brought into service at the end of the first quarter. The Company continues to expect these wells to meet Karr area development needs as production ramps up. Per unit operating and transportation costs are expected to decline as the Company ramps up production in the fourth quarter of 2020 and into 2021.

The five-wells on the 2-1 pad averaged gross peak 30-day production per well of 1,463 Boe/d, including 735 Bbl/d of wellhead liquids, and an average wellhead CGR of 168 Bbl/MMcf.[1] These wells exhibit higher gas production compared to other recently drilled Karr wells, which is in line with expectations.

In 2020, Paramount implemented data analytics workflows that incorporate and leverage proprietary geoscience characterization and daily well performance with public data sources. Utilizing this data foundation, Paramount is able to generate advanced predictive models to rapidly assess development opportunities at its Grande Prairie Montney assets under a variety of scenarios and implement changes to completion design, well spacing and other factors to maximize returns. Improved completion design is one of the primary reasons that costs in the Karr area have been trending downward while completion effectiveness has been maintained. All-in DCET costs at the 2-1 pad averaged $7.3 million per well, representing a 39 percent reduction compared with average DCET costs for Karr wells in 2018 and 2019.

At the five-well 5-16 West pad, completion activities were recently concluded and preliminary lease construction, drilling and completion costs are coming in at an estimated $7.2 million per well. The pre-building and modularization of above ground well equipment packages on this pad improved schedule efficiency, and the Company anticipates bringing these wells on production in late November.

Paramount recently commenced drilling six Middle Montney wells on the Karr 3-10 pad. The Company plans to complete, tie-in and bring on production all six of these wells in the first half of 2021. Additionally, lease construction at the five-well 7-18 pad has begun, with drilling anticipated to start in December 2020.

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[1] Production measured at the wellhead. Natural gas sales volumes are lower by approximately 7 percent and liquids sales volumes are lower by approximately 7 percent 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. CGRs are calculated by dividing raw wellhead liquids volumes by raw wellhead natural gas

volumes. See Oil and Gas Measures and Definitions in the Advisories section.

The following table summarizes the performance of Karr wells on the 2-1, 12-18, 1-19, and 4-24 pads, as well as the five wells drilled in 2018 and the 27 wells drilled in the 2016/2017 capital program at Karr:

	Peak 30-Day (1)			**Cumulative (2)**			**Days on Production**
	Total	**Wellhead Liquids**	**CGR (3)**	**Total**	**Wellhead Liquids**	**CGR (3)**	
	(Boe/d)	*(Bbl/d)*	*(Bbl/MMcf)*	*(MBoe)*	*(MBbl)*	*(Bbl/MMcf)*	
2-1 Pad							
03/14-12-066-05W6/0	1,490	764	175	87	39	133	67
04/16-12-066-05W6/0	1,723	977	218	97	50	174	65
05/15-12-066-05W6/0	1,376	621	137	88	40	137	67
05/16-12-066-05W6/0	1,428	667	146	92	45	160	66
06/15-12-066-05W6/0	1,300	646	165	84	39	144	65
Avg. per well	**1,463**	**735**	**168**	**90**	**43**	**151**	**66**
12-18 Pad							
00/09-17-065-05W6/2	1,304	1,056	710	85	67	616	127
00/16-17-065-05W6/0	1,644	1,262	550	125	92	476	124
02/09-17-065-05W6/0	1,757	1,350	553	145	107	473	127
02/16-17-065-05W6/0	1,692	1,181	385	166	111	335	128
03/09-17-065-05W6/0	1,567	1,232	614	146	111	533	127
Avg. per well	**1,593**	**1,216**	**538**	**133**	**98**	**454**	**127**
1-19 Pad							
03/13-29-065-05W6/0	1,704	1,209	407	339	228	342	312
03/14-29-065-05W6/0	1,357	1,067	611	192	142	474	244
04/13-29-065-05W6/0	1,566	1,170	493	279	195	386	304
Avg. per well	**1,542**	**1,149**	**486**	**270**	**188**	**384**	**287**
4-24 Pad							
00/01-11-065-06W6/0	1,878	1,271	349	408	242	244	407
00/02-12-065-06W6/0	1,836	1,308	413	329	223	351	412
00/03-12-065-06W6/0	2,307	1,583	365	527	330	279	425
00/04-12-065-06W6/0	2,097	1,329	289	537	316	238	418
02/03-12-065-06W6/0	2,029	1,308	302	463	284	263	419
Avg. per well	**2,029**	**1,360**	**338**	**453**	**279**	**268**	**416**
2018 Wells							
5 wells (Avg. per well)	1,877	1,121	247	651	337	180	680
2016/2017 Wells							
27 wells (Avg. per well)	1,969	1,171	245	758	377	165	918

(1) Peak 30-Day is the highest daily average production rate over a 30-day consecutive period for each well, measured at the wellhead. Natural gas sales volumes are approximately 7 percent lower and liquids sales volumes are approximately 7 percent lower due to shrinkage. Excludes days when the wells did not produce. The production rates and volumes shown are 30-day peak rates 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. These wells were produced at restricted rates from time-to-time due to facility and gathering system constraints. See "Oil and Gas Measures and Definitions" in the Advisories.

(2) Cumulative is the aggregate production measured at the wellhead to October 31, 2020. Natural gas sales volumes are approximately 7 percent lower and liquids sales volumes are approximately 7 percent lower due to shrinkage. These wells were produced at restricted rates from time-to-time due to facility and gathering system constraints. The production rates and volumes shown are not necessarily indicative of average daily production, long-term performance or of ultimate recovery from the wells.

(3) CGRs calculated by dividing raw wellhead liquids volumes by raw wellhead natural gas volumes.

Wapiti

Wapiti sales volumes and netbacks are summarized below:

	Q3 2020	Q2 2020	*% Change*
Sales volumes			
Natural gas (MMcf/d)	**17.8**	31.9	*(44)*
Condensate and oil (Bbl/d)	**4,414**	8,786	*(50)*
Other NGLs (Bbl/d)	**548**	841	*(35)*
Total (Boe/d)	**7,925**	14,940	*(47)*
% liquids	***63%***	*64%*	

Netback	($ millions)	($/Boe)	($ millions)	($/Boe)	% Change in $ millions
Petroleum and natural gas sales	**24.1**	***33.10***	30.7	*22.61*	*(21)*
Royalties	**(0.9)**	***(1.18)***	(1.0)	*(0.70)*	*(10)*
Operating expense	**(12.3)**	***(16.88)***	(15.9)	*(11.69)*	*(23)*
Transportation and NGLs processing	**(4.7)**	***(6.42)***	(5.8)	*(4.24)*	*(19)*
	6.2	***8.62***	8.0	*5.98*	*(23)*

Third quarter sales volumes at Wapiti averaged 7,925 Boe/d (63 percent liquids) compared to 14,940 Boe/d (64 percent liquids) in the second quarter. Production was shut-in due to a six-week unplanned outage at the Wapiti Plant. Paramount is pursuing a claim under its contingent business interruption insurance policy related to the outage. The policy has a 30-day waiting period and recoveries are expected to exceed $5 million.

Completion operations at the five-well 5-3 West pad commenced in October, and despite utilizing higher fluid and proppant intensity compared to the 5-3 East pad drilled in 2019, the Company estimates per well completion costs to come in approximately 30 percent lower as a result of improved efficiencies and completion design. Preliminary lease construction, drilling and completion costs are estimated at $7.3 million per well. Paramount plans to equip, tie-in and bring on production these five wells in the coming months.

Drilling of the remaining six wells on the eight-well (four Middle Montney and four Lower Montney) Wapiti 6-4 pad is scheduled to commence late in the fourth quarter. The Company plans to complete, tie-in and bring on production all eight wells in mid-2021.

The following table summarizes the performance of Wapiti wells on the 5-3 East and 9-3 pads:

	Peak 30-Day (1)			**Cumulative (2)**			
	Total	**Wellhead Liquids**	**CGR (3)**	**Total**	**Wellhead Liquids**	**CGR (3)**	**Days on Production**
	(Boe/d)	*(Bbl/d)*	*(Bbl/MMcf)*	*(MBoe)*	*(MBbl)*	*(Bbl/MMcf)*	
5-3 East Pad							
03/11-27-067-06W6/0	2,174	1,360	279	263	151	226	263
04/06-15-068-06W6/0	1,703	1,154	351	190	124	313	224
02/09-28-067-06W6/0	1,797	1,130	283	152	92	257	145
02/11-27-067-06W6/0	2,017	1,296	299	248	150	256	257
00/12-27-067-06W6/0	1,390	926	332	158	95	250	195
02/12-27-067-06W6/0	1,949	1,277	317	209	120	224	197
00/09-28-067-06W6/0	1,585	1,060	336	179	106	241	173
03/06-15-068-06W6/0	1,409	984	385	184	125	350	211
00/05-15-068-06W6/0	1,432	1,018	410	155	109	387	193
02/05-15-068-06W6/0	1,563	1,070	362	172	116	339	182
00/08-16-068-06W6/0	1,396	934	338	170	112	317	177
02/08-16-068-06W6/0	1,711	1,214	407	129	88	357	101
Avg. per well	**1,677**	**1,119**	**334**	**184**	**116**	**282**	**193**
9-3 Pad							
00/11-27-067-06W6/0	1,360	880	306	246	152	268	364
03/08-15-068-06W6/0	962	689	421	176	126	414	331
04/09-27-067-06W6/0	1,536	1,102	423	368	229	276	447
03/09-27-067-06W6/0	1,268	794	279	334	205	265	448
02/06-15-068-06W6/0	1,511	1,088	429	234	158	347	316
02/09-27-067-06W6/0	1,094	769	395	298	187	282	429
03/07-15-068-06W6/0	1,042	787	516	229	151	318	414
02/10-27-067-06W6/0	1,137	779	362	289	181	278	409
03/10-27-067-06W6/0	1,111	749	345	292	173	244	429
02/08-15-068-06W6/0	969	693	419	207	139	338	385
02/07-15-068-06W6/0	1,192	815	360	227	152	340	371
Avg. per well	**1,198**	**831**	**378**	**264**	**168**	**295**	**395**

(1) Peak 30-Day is the highest daily average production rate over a 30-day consecutive period for each well, measured at the wellhead. Natural gas sales volumes are approximately 11 percent lower and liquids sales volumes are approximately 3 percent lower due to shrinkage under normalized operations. Excludes days when the wells did not produce. The production rates and volumes shown are 30-day peak rates 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. These wells were produced at restricted rates from time-to-time due to facility and gathering system constraints. See "Oil and Gas Measures and Definitions" in the Advisories

(2) Cumulative is the aggregate production measured at the wellhead to October 31, 2020. Natural gas sales volumes are approximately 11 percent lower and liquids sales volumes are approximately 3 percent lower due to shrinkage under normalized operating conditions. These wells were produced at restricted rates from time-to-time due to facility and gathering system constraints. The production rates and volumes shown are not necessarily indicative of average daily production, long-term performance or of ultimate recovery from the

wells
(3) CGRs calculated by dividing raw wellhead liquids volumes by raw wellhead natural gas volumes

KAYBOB REGION

Kaybob Region sales volumes averaged 25,477 Boe/d (26 percent liquids) in the third quarter compared to 29,561 Boe/d (26 percent liquids) in the second quarter. The quarter over quarter decrease was primarily attributable to natural declines and planned maintenance outages during the third quarter. The Company completed a major turnaround in the quarter of its Presley 3-29 facility on schedule, under budget and without incident.

Paramount continues to focus on operational excellence, making progress on improving its cost structure while maintaining best practices in safety, asset integrity, reliability and environmental performance. Improvements in operational efficiency have been especially impactful in the Kaybob Region, resulting in significant cost savings compared with previous years.

Paramount holds material positions in the Duvernay and Montney resource plays in the Kaybob Region that will compete for capital in the medium term. The Company is monitoring regional competitor activity and using this information to evaluate the full field development plans for these plays. Recent competitor results have been encouraging, including an offsetting well just north-east of the Company's Kaybob North Duvernay field that appears to have produced the highest ever monthly oil/condensate volume for a Duvernay well in the basin.

Supporting production in the Region is a network of owned infrastructure including the Company's crude oil terminal that was first put into service in the fourth quarter of 2019. The pipeline connected terminal provides Paramount the opportunity to increase netbacks for its Kaybob area crude and condensate volumes and capture incremental value in price differentials.

CENTRAL ALBERTA AND OTHER REGION

Central Alberta and Other Region sales volumes averaged 8,350 Boe/d (14 percent liquids) compared to 8,239 Boe/d (12 percent liquids) in the second quarter.

Paramount holds a material, contiguous Duvernay position at Willesden Green and continues to actively evaluate longer-term full field development plans for this asset.

GREENHOUSE GAS REDUCTION INITIATIVE

As part of Paramount's continued commitment to responsible energy development, the Company has been participating in GHG emission reduction programs and investing in new equipment to reduce GHG emissions from its operations. Upstream emissions intensity (combined Scope 1 and Scope 2) was 18.5 kg CO_2e/Boe in 2019, an 18 percent reduction from the previous year. This compares to the Oil and Gas Climate Initiative ("OGCI") group average of 21.1 kg CO_2e/Boe in 2019 and their stated target of 20.0 kg CO_2e/Boe by the year 2025. OGCI is an international industry-led organization comprised of 12 of the world's largest energy companies, representing over one fifth of global oil and gas production.

The Company has completed its project in the Grande Prairie area to replace approximately 200 high-bleed controllers with modern low-bleed units at well sites. These new units are expected to eliminate approximately 8,600 tonnes of GHG emissions per year and generate approximately $0.5 million in GHG credits under current regulations through 2022. This project, which was part of a larger, multi-year initiative where approximately 1,900 high-bleed controllers have been replaced, is estimated to reduce annual GHG emissions by approximately 75,000 tonnes of CO2e when compared to baseline 2017 emissions.[1] Paramount continues to evaluate its assets for further methane reduction opportunities.

(1) Excludes GHG emissions related to certain natural gas-weighted properties that were sold in late 2019.

HEDGING

The Company's commodity hedging position as at September 30, 2020 is summarized below:

- Natural Gas:

Rest of 2020	~60,000 MMBtu/d at US$2.58/MMBtu ~66,800 GJ/d at CDN$2.18/GJ
2021	~67,500 MMBtu/d at US$2.73/MMBtu ~60,000 GJ/d at CDN$2.54/GJ

- Oil:

Rest of 2020 ~4,000 Bbl/d at CDN$80.11/Bbl
~9,700 Bbl/d at US$43.22/Bbl
2021 5,000 Bbl/d at US$44.10/Bbl

Subsequent to September 30, 2020, the Company hedged the differential on 1,000 Bbl/d of condensate at Edmonton for the first quarter of 2021 at WTI plus US$0.50/Bbl.

Further details of Paramount's commodity hedging position are provided in its third quarter 2020 Management's Discussion and Analysis and Consolidated Financial Statements.

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 2020 results, including Management's Discussion and Analysis and the Company's Consolidated Financial Statements can be obtained at
https://mma.prnewswire.com/media/1328030/Paramount_Resources_Ltd__Paramount_Resources_Ltd__Reports_Third.pdf

This information will also be made available through Paramount's website at www.paramountres.com and on SEDAR at www.sedar.com. A summary of historical financial and operating results is also available on Paramount's website at http://www.paramountres.com/investor-relations/financial-reports#2020.

FINANCIAL AND OPERATING RESULTS [1]
($ millions, except as noted)

	Q3 2020		Q2 2020	
Net loss	**(23.3)**		(75.7)	
per share – basic and diluted ($/share)	***(0.17)***		*(0.57)*	
Cash from (used in) operating activities	**11.4**		(14.2)	
per share – basic and diluted ($/share)	***0.09***		*(0.11)*	
Adjusted funds flow	**29.5**		19.0	
per share – basic and diluted ($/share)	***0.22***		*0.14*	
Total assets	**3,041.9**		3,066.4	
Long-term debt	**792.7**		754.9	
Net debt	**836.5**		810.7	
Common shares outstanding *(thousands)*[2]	**133,784**		133,784	
Sales volumes				
Natural gas (MMcf/d)	**224.0**		253.2	
Condensate and oil (Bbl/d)	**19,782**		22,823	
Other NGLs (Bbl/d) [3]	**3,952**		3,817	
Total (Boe/d)	**61,064**		68,839	
% liquids	***39%***		*39%*	
Grande Prairie Region (Boe/d)	**27,237**		31,039	
Kaybob Region (Boe/d)	**25,477**		29,561	
Central Alberta and Other Region (Boe/d)	**8,350**		8,239	
Total (Boe/d)	**61,064**		68,839	
Netback		*$/Boe* [4]		*$/Boe* [4]
Natural gas revenue	**40.0**	***1.94***	44.7	*1.94*
Condensate and oil revenue	**88.7**	***48.74***	60.3	*29.05*
Other NGLs revenue [3]	**6.6**	***18.10***	4.3	*12.28*
Royalty and sulphur revenue	**3.5**	–	3.9	–
Petroleum and natural gas sales	**138.8**	***24.70***	113.2	*18.07*
Royalties	**(4.3)**	***(0.77)***	(3.6)	*(0.57)*
Operating expense	**(62.4)**	***(11.10)***	(62.6)	*(9.99)*
Transportation and NGLs processing [5]	**(27.8)**	***(4.95)***	(25.3)	*(4.04)*
Netback	**44.3**	***7.88***	21.7	*3.47*
Commodity contract settlements	**9.8**	***1.75***	12.9	*2.05*
Netback including commodity contract settlements	**54.1**	***9.63***	34.6	*5.52*
Total Capital Expenditures				
Grande Prairie Region	**46.1**		36.7	
Kaybob Region	**2.7**		1.8	
Central Alberta and Other Region	**0.2**		0.8	
Corporate	**1.5**		1.5	

Land and property acquisitions	–	0.6
Total capital expenditures	**50.5**	41.4
Asset retirement obligation settlements	**0.7**	4.0

(1) Readers are referred to the advisories concerning Non-GAAP Measures and Oil and Gas Measures and Definitions in the Advisories section of this document. This table contains the following Non-GAAP measures: Adjusted Funds Flow, Net Debt, Netback, and Total Capital Expenditures
(2) Common shares are presented net of shares held in trust under the Company's restricted share unit plan (000's of common shares): Q3 2020: 414 and Q2 2020: 414
(3) Other NGLs means ethane, propane and butane
(4) Natural gas revenue presented as $/Mcf
(5) Includes downstream transportation costs and NGLs fractionation costs

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:

- planned capital expenditures for 2020;
- anticipated sales volumes in the fourth quarter of 2020;
- the expectation that Paramount will finalize its 2021 capital budget and related guidance in the first quarter of 2021;
- preliminary anticipated capital expenditures in 2021 and the resulting expected 2021 average sales volumes and excess of adjusted funds flow over such expenditures;
- planned exploration, development and production activities;
- estimated lease construction, drilling and completion costs;
- expected GHG reductions and credits associated with controller upgrades;
- planned abandonment and reclamation expenditures using funding under the Alberta Site Rehabilitation Program;
- anticipated operating costs in the fourth quarter of 2020;
- the expectation that two additional water disposal wells will meet Karr area development needs as production ramps up;
- the expectation that per unit operating and transportation costs at Karr will continue to decline as the Company ramps up production in the fourth quarter of 2020 and into 2021; and
- expected recoveries under Paramount's contingent business interruption insurance related to the Wapiti Plant outage.

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 natural gas and liquids 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, general & administrative and other costs;
- foreign currency exchange rates and interest rates;
- general business, economic and market conditions;
- 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 natural gas and liquids 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, liquids 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;
- the application of Paramount's contingent business interruption insurance policy to the Wapiti Plant outage; 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).

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:

- those risks set out in the Management's Discussion and Analysis for the three and nine months ended September 30, 2020 ("MD&A") under "Risk Factors";
- fluctuations in natural gas and liquids 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 2021 capital expenditures prior to finalization and changes to the resulting expected 2021 average sales volumes and excess of adjusted funds flow over such expenditures;
- changes in foreign currency exchange rates and interest rates;
- the uncertainty of estimates and projections relating to future revenue, production, reserve additions, liquids 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 flow from operations 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 obtain 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.

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, 2019 and in the MD&A, which are 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.

Non-GAAP Measures

In this press release, "Adjusted funds flow", "Netback", "Net Debt" and "Total Capital Expenditure", together the "Non-GAAP 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, reorganization costs and provision and other. 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, 2020 and June 30, 2020:

	Sept 30,	Jun 30,

Three months ended	2020 (MM$)	2020 (MM$)
Cash from (used in) operating activities	**11.4**	**(14.2)**
Change in non-cash working capital	15.6	24.0
Geological and geophysical expenses	1.7	1.9
Asset retirement obligations settled	0.7	4.0
Reorganization costs	—	3.0
Provision and other	0.1	0.3
Adjusted funds flow	**29.5**	**19.0**

"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 table under the heading "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 MD&A for the calculation of Net Debt.

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

Non-GAAP 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 measures are unlikely to be comparable to similar measures presented by other issuers.

Oil and Gas Measures and Definitions

The term "liquids" includes oil, condensate and Other NGLs (ethane, propane and butane). NGLs consist of condensate and Other NGLs.

Abbreviations

Liquids	
Bbl	Barrels
Bbl/d	Barrels per day
MBbl	Thousands of barrels
NGLs	Natural gas liquids
Condensate	Pentane and heavier hydrocarbons

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

Natural Gas	
GJ	Gigajoules
GJ/d	Gigajoules per day
Mcf	Thousands of cubic feet
MMcf	Millions of cubic feet
MMcf/d	Millions of cubic feet per day
AECO	AECO-C reference price
WTI	West Texas Intermediate

This press release contains disclosures expressed as "Boe", "$/Boe", "MBoe", "MMBoe" 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, 2020, the value ratio between crude oil and natural gas was approximately 23:1. 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 this oil and gas metric for its own performance measurements and to provide shareholders with measures to compare the Company's performance over time; however, such measure is not a reliable indicator 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, including a breakdown of 2019 annual and quarterly production volumes by product type, is provided in the Company's annual information form for the year ended December 31, 2019 which is available on SEDAR at www.sedar.com.

SOURCE Paramount Resources Ltd.

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