Paramount Resources Ltd.

Paramount Resources Ltd. Reports Second Quarter 2020 Results

CALGARY, AB, Aug. 6, 2020 /CNW/ -

HIGHLIGHTS

- Sales volumes averaged 68,839 Boe/d (39 percent liquids) in the second quarter of 2020 compared to 70,022 Boe/d (38 percent liquids) in the first quarter.
    - At Wapiti, second quarter sales volumes increased 107 percent to 14,940 Boe/d (64 percent liquids) compared to the first quarter as run time at the third-party processing facility improved.
    - At Karr, the five wells on the 12-18 pad were flowed through test facilities partway through the quarter and were brought on production through permanent facilities in early July. Average gross peak 30-day production per well was 1,593 Boe/d, including 1,216 Bbl/d of wellhead liquids, with an average wellhead CGR of 538 Bbl/MMcf. (1)
    - Average sales volumes in the quarter were impacted by shut-ins and curtailments.
- Second quarter operating costs were $62.6 million ($9.99/Boe), a reduction of about 30 percent quarter-over-quarter. Approximately 30 to 50 percent of this reduction is attributable to sustainable improvements in the Company's cost structure.
- Paramount's netback was $21.7 million in the second quarter of 2020 compared to $44.5 million in the first quarter of 2020, reflecting the impact of substantially lower commodity prices which were only partially offset by cost improvements. (2)
- Adjusted funds flow was $19.0 million or $0.14 per share.(2) Cash from operating activities was ($14.2) million in the second quarter of 2020, largely because of changes in working capital.
- Second quarter capital spending totaled $41.4 million, primarily related to drilling and completion activities at Karr and drilling operations at Wapiti.
- The Company has realized significant cost savings in its capital program through its continuing 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 (three Middle Montney and two Lower Montney) Karr 12-18 pad averaged $8.8 million per well, $0.7 million lower than prior estimates. This represents a 27 percent reduction compared with average DCET costs for all Karr wells in 2018 and 2019.
    - Drilling operations were concluded in the second quarter on the five-well (three Upper Montney and two Middle Montney) Karr 5-16 West pad. Average drilling costs of $2.7 million per well were in line with recent pacesetters at Karr.
    - Completion activities at the five-well (all Middle Montney) Karr 2-1 pad have recently been concluded and preliminary lease construction, drilling and completion costs are coming in at a pacesetting estimate of $7.0 million per well.
    - At Wapiti, drilling operations were completed on the five-well (two Middle Montney and three Lower Montney) 5-3 West pad, with estimated costs averaging $3.1 million per well.
- The expansion of the third-party Karr 6-18 facility was completed in July. The additional raw gas and liquids processing capacity adds flexibility to the Company's Karr operations, including minimizing the impact of future disruptions at other accessible third-party processing facilities.
- Paramount has received approval for up to $8 million of funding under the Alberta Site Rehabilitation Program and applied for funding under similar programs in BC and Saskatchewan. The majority of activities to be funded under the Alberta Site Rehabilitation Program are expected to occur in 2021.
- The Company advanced its project to replace 200 high-bleed controllers with low-bleed units at well sites in the Grande Prairie area in 2020, with 164 low-bleed units installed to date. The project is anticipated to eliminate approximately 8,600 tonnes of greenhouse gas ("GHG") emissions annually. In addition, reduced trucking of produced water following the start-up of two new water disposal wells at Karr is expected to eliminate approximately 13,500 tonnes per year of GHG emissions (the equivalent of removing approximately 2,900 passenger cars from use) while also reducing operating costs.

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(1) Production measured at the wellhead. Natural gas sales volumes are lower by approximately 10 percent and wellhead liquids sales volumes are lower by approximately 12 percent due to shrinkage, under normalized operations. 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.

CORPORATE

- Paramount is on track to achieve its previously announced 2020 cost reduction targets of $25 million in operating costs and $15 million in general and administrative expenses.
- The Company is maintaining its 2020 capital guidance of $165 million and allocating the significant capital savings it is realizing to advance certain projects that had previously been planned for 2021. Paramount continues to evaluate the merits of accelerating additional projects as market conditions evolve.
- Approximately 4,300 Boe/d of production currently remains shut-in and Paramount continues to review opportunities to bring volumes back online as conditions improve.
- Sales volumes are anticipated to average between 65,000 Boe/d and 70,000 Boe/d in the second half of 2020.
- Reflective of the macro economic environment and significant reduction in commodity prices, in June 2020 Paramount's senior secured revolving bank credit facility was amended to provide a period of financial covenant relief to and including June 30, 2021 and to amend the size of the facility to $1.0 billion. Long-term debt at June 30, 2020 was $754.9 million.
- In July 2020 the Company's unsecured demand revolving letter of credit facility was increased from $40 million to $70 million.
- The Company has entered into additional 2020 natural gas and liquids hedges to mitigate volatility and protect cash flows. See "Hedging" below for a summary of the Company's current hedge position.
- Paramount continues to respond to the COVID-19 pandemic. At the beginning of June, Paramount implemented a plan to safely transition its Calgary head office employees from remote work back to the office.

REVIEW OF OPERATIONS

GRANDE PRAIRIE REGION

Grande Prairie Region sales volumes and netbacks are summarized below:

	Q2 2020		Q1 2020		*% Change*
Sales volumes					
Natural gas (MMcf/d)	**78.3**		74.6		*5*
Condensate and oil (Bbl/d)	**16,309**		14,097		*16*
Other NGLs (Bbl/d)	**1,680**		1,680		*–*
Total (Boe/d)	**31,039**		28,214		*10*
% liquids	***58%***		*56%*		
Netback	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	*% Change in $millions*
Petroleum and natural gas sales	**60.3**	***21.34***	91.7	*35.71*	*(34)*
Royalties [(1)]	**0.3**	***0.12***	(6.2)	*(2.42)*	*NM*
Operating expense	**(38.8)**	***(13.73)***	(42.4)	*(16.53)*	*(8)*
Transportation and NGLs processing	**(12.9)**	***(4.58)***	(10.3)	*(4.03)*	*25*
	8.9	***3.15***	32.8	*12.73*	*(73)*

(1) Second quarter royalties were impacted by lower prices and adjustments related to prior year gas cost allowance.
NM Not meaningful

Karr

Karr sales volumes and netbacks are summarized below:

	Q2 2020		Q1 2020		*% Change*
Sales volumes					
Natural gas (MMcf/d)	**46.1**		59.4		*(22)*
Condensate and oil (Bbl/d)	**7,501**		9,691		*(23)*
Other NGLs (Bbl/d)	**829**		1,290		*(36)*
Total (Boe/d)	**16,009**		20,885		*(23)*
% liquids	***52%***		*53%*		
Netback	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	*% Change in $ millions*
Petroleum and natural gas sales	**29.4**	***20.20***	64.2	*33.76*	*(54)*
Royalties [(1)]	**1.3**	***0.87***	(5.0)	*(2.62)*	*NM*
Operating expense	**(22.4)**	***(15.39)***	(30.8)	*(16.19)*	*(27)*
Transportation and NGLs processing	**(7.2)**	***(4.91)***	(6.7)	*(3.54)*	*7*
	1.1	***0.77***	21.7	*11.41*	*(95)*

(1) Second quarter royalties were impacted by lower prices and adjustments related to prior year gas cost allowance.
NM Not meaningful

Second quarter sales volumes at Karr averaged 16,009 Boe/d compared to 20,885 Boe/d in the first quarter. Sales volumes were impacted by a seven-day planned outage (including ramp-down and ramp-up periods) at the third-party Karr 6-18 facility related to the completion of expansion activities and the temporary shut-in of certain offsetting wells due to completion activities at the 12-18 and 2-1 pads, as well as by natural declines.

In addition to previously installed gas lift and related compression at pads near the southwest terminus of Paramount's gathering system, work is ongoing to mitigate current and future potential back-out issues in the Karr gathering system as new production continues to be brought online. This includes additional booster compression that is scheduled to be brought into service midway through the third quarter to mitigate production currently backed-out.

Substantial operating cost savings have been realized with the addition of the Company's two new water disposal wells that were brought into service near the end of the first quarter. These wells have accommodated the disposal of substantially all produced water from Karr area wells and resulted in approximately $4 million in operating costs savings compared to the previous quarter from the elimination of trucking and third-party disposal fees. These wells are expected to meet Karr area development needs for the foreseeable future.

Final DCET costs for the 12-18 pad came in at a pacesetting $8.8 million average per well, $0.7 million per well lower than previously estimated. This represents a 27 percent reduction compared with average DCET costs for all Karr wells in 2018 and 2019. The wells (three Middle Montney and two Lower Montney) flowed through testers partway through the quarter and began producing through permanent facilities in early July. Average gross peak 30-day production per well was 1,593 Boe/d, including 1,216 Bbl/d of wellhead liquids, with an average wellhead CGR of 538 Bbl/MMcf. (1)

Paramount completed the drilling of five wells (three Upper Montney and two Middle Montney) on the 5-16 West pad during the second quarter. Average drilling costs of $2.7 million per well are in line with the pacesetting results at the 2-1 pad drilled in the fourth quarter of 2019. The successful negotiation of lower vendor rates and the continuous improvement from prior drilling operations helped achieve this result. Paramount plans to complete, tie-in, and bring on production all five wells on the 5-16 West pad in 2021.

Completion activities at the five-well Middle Montney Karr 2-1 pad have recently been concluded and preliminary lease construction, drilling and completion costs are coming in at a pacesetting estimate of $7.0 million per well. Paramount continues to aggressively pursue capital cost savings without compromising on completion effectiveness. The Company plans to tie-in and bring on production the wells on the 2-1 pad in the third quarter.

The Karr 6-18 third-party processing facility expansion has been completed and commercial operations commenced in July 2020. The facility now has 150 MMcf/d of total raw gas handling capacity, including 70 MMcf/d of sour raw gas processing, and 30,000 Bbl/d of raw hydrocarbon liquids handling capacity. The additional gas and liquids processing capacity will allow the Company to grow future production as well as minimize the impact of future disruptions at the other accessible third-party processing facilities.

(1) Production measured at the wellhead. Natural gas sales volumes are lower by approximately 10 percent and wellhead liquids sales volumes are lower by approximately 12 percent due to shrinkage, under normalized operations. 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 the wells on the 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)**			
	Total	**Wellhead Liquids**	**CGR (3)**	**Total**	**Wellhead Liquids**	**CGR (3)**	**Days on Production**
	(Boe/d)	*(Bbl/d)*	*(Bbl/MMcf)*	*(MBoe)*	*(MBbl)*	*(Bbl/MMcf)*	
12-18 Pad							
00/09-17-065-05W6/2	1,304	1,056	710	43	35	694	36
00/16-17-065-05W6/0	1,644	1,262	550	56	43	540	36
02/09-17-065-05W6/0	1,757	1,350	553	60	46	542	36
02/16-17-065-05W6/0	1,692	1,181	385	58	40	378	36
03/09-17-065-05W6/0	1,567	1,232	614	55	42	571	36
Avg. per well	**1,593**	**1,216**	**538**	**54**	**41**	**520**	**36**
01-19 Pad							
03/13-29-065-05W6/0	1,704	1,209	407	279	187	340	229
03/14-29-065-05W6/0	1,357	1,067	611	167	124	479	206
04/13-29-065-05W6/0	1,566	1,170	493	229	162	406	223
Avg. per well	**1,542**	**1,149**	**486**	**225**	**158**	**390**	**219**
04-24 Pad							
00/01-11-065-06W6/0	1,878	1,271	349	351	211	250	315
00/02-12-065-06W6/0	1,836	1,308	413	284	194	360	320
00/03-12-065-06W6/0	2,307	1,583	365	460	293	291	333

00/04-12-065-06W6/0	2,097	1,329	289	468	279	245	326
02/03-12-065-06W6/0	2,029	1,308	302	406	251	270	327
Avg. per well	**2,029**	**1,360**	**338**	**394**	**246**	**276**	**324**
2018 Wells							
5 wells (Avg. per well)	1,877	1,121	247	629	327	180	624
2016/2017 Wells							
27 wells (Avg. per well)	1,969	1,171	245	738	368	166	860

(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 10 percent lower and wellhead liquids sales volumes are approximately 12 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 July 31, 2020. Natural gas sales volumes are approximately 10 percent lower and wellhead liquids sales volumes are approximately 12 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:

	Q2 2020		Q1 2020		*% Change*
Sales volumes					
Natural gas (MMcf/d)	**31.9**		14.8		*116*
Condensate and oil (Bbl/d)	**8,786**		4,364		*101*
Other NGLs (Bbl/d)	**841**		386		*118*
Total (Boe/d)	**14,940**		7,209		*107*
% liquids		***64%***		*66%*	
Netback	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	*% Change in $ millions*
Petroleum and natural gas sales	**30.7**	***22.61***	27.2	*41.53*	*13*
Royalties	**(1.0)**	***(0.70)***	(1.2)	*(1.85)*	*(17)*
Operating expense	**(15.9)**	***(11.69)***	(11.2)	*(17.11)*	*42*
Transportation and NGLs processing	**(5.8)**	***(4.24)***	(3.6)	*(5.46)*	*61*
	8.0	***5.98***	11.2	*17.11*	*(29)*

Second quarter sales volumes at Wapiti averaged 14,940 Boe/d (64 percent liquids) compared to 7,209 Boe/d (66 percent liquids) in the first quarter. Run time at the third-party operated processing facility was significantly improved compared with previous quarters.

All 12 wells on the 5-3 East pad are now flowing through permanent production facilities as additional third-party effluent gathering system capacity came online during the second quarter.

Paramount completed the drilling of five wells (two Middle Montney and three Lower Montney) on the 5-3 West pad at an average cost of $3.1 million per well in the second quarter. Plans to complete and bring on production these wells and drill the remaining six wells on the eight-well 6-4 pad have been deferred. A tenure well drilled and completed in 2015 is planned to be brought on production in the third quarter.

The following table summarizes the performance of 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	2,226	1,412	289	240	143	246	209
04/06-15-068-06W6/0	1,736	1,187	360	168	112	336	172
02/09-28-067-06W6/0	1,776	1,110	278	142	88	271	118
02/11-27-067-06W6/0	2,076	1,344	306	224	139	274	203
00/12-27-067-06W6/0	1,393	928	333	131	81	270	141
02/12-27-067-06W6/0	1,998	1,326	329	182	110	253	144
00/09-28-067-06W6/0	1,701	1,155	353	168	104	271	130
03/06-15-068-06W6/0	1,465	1,036	403	159	111	382	161
00/05-15-068-06W6/0	1,480	1,066	429	133	94	407	142

02/05-15-068-06W6/0	1,663	1,170	396	149	103	375	131
00/08-16-068-06W6/0	1,516	1,055	381	145	98	351	127
02/08-16-068-06W6/0	1,845	1,348	452	119	84	403	77
Avg. per well	**1,740**	**1,178**	**350**	**163**	**106**	**305**	**146**
9-3 Pad							
00/11-27-067-06W6/0	1,360	880	306	228	143	279	310
03/08-15-068-06W6/0	962	689	421	162	119	452	279
04/09-27-067-06W6/0	1,536	1,102	423	348	219	284	394
03/09-27-067-06W6/0	1,268	794	279	316	198	277	395
02/06-15-068-06W6/0	1,511	1,088	429	219	152	379	263
02/09-27-067-06W6/0	1,094	769	395	281	179	293	375
03/07-15-068-06W6/0	1,042	787	516	216	145	338	361
02/10-27-067-06W6/0	1,137	779	362	273	174	292	356
03/10-27-067-06W6/0	1,111	749	345	276	167	256	376
02/08-15-068-06W6/0	969	693	419	193	133	365	332
02/07-15-068-06W6/0	1,192	815	360	210	143	357	318
Avg. per well	**1,198**	**831**	**378**	**247**	**161**	**311**	**342**

(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 wellhead 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 July 31, 2020. Natural gas sales volumes are approximately 11 percent lower and wellhead 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 29,561 Boe/d (26 percent liquids) in the second quarter compared to 32,700 Boe/d (29 percent liquids) in the first quarter. This decrease was mainly attributable to natural declines and shut-ins during the second quarter.

Paramount holds material positions in Duvernay and Montney Oil resource plays in the Kaybob Region that will compete for capital in the medium term. The Company continues to actively evaluate longer-term full field development plans for these plays.

CENTRAL ALBERTA AND OTHER REGION

Central Alberta and Other Region sales volumes averaged 8,239 Boe/d (12 percent liquids) in the second quarter compared to 9,108 Boe/d (14 percent liquids) in the first quarter. Sales at Birch were impacted by planned and unplanned plant outages 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 of the 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.

The Company is continuing upgrades at various sites to replace its remaining high-bleed controllers with modern low-bleed units. A total of 200 low-bleed units are expected to be installed in the Grand Prairie Region in 2020, with 164 installed to date. 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.

Reduced trucking of produced water with the start-up of two new water disposal wells at Karr is expected to eliminate approximately 13,500 tonnes per year of GHG emissions (the equivalent of removing approximately 2,900 passenger cars from use) while also reducing operating costs.

HEDGING

The tables below set out the Company's hedge position:

Oil	Volume	Price	Remaining term
NYMEX WTI Swaps (Sale)	4,000 Bbl/d	CDN$80.11/Bbl	July 2020 – December 2020
NYMEX WTI Swaps (Sale)	6,000 Bbl/d	US$41.75/Bbl	August 2020
NYMEX WTI Swaps (Sale)	16,000 Bbl/d	US$42.23/Bbl	September 2020
NYMEX WTI Swaps (Sale)	6,000 Bbl/d	US$43.03/Bbl	October 2020
NYMEX WTI Swaps (Sale)	4,000 Bbl/d	US$43.73/Bbl	November 2020
NYMEX WTI Swaps (Sale)	4,000 Bbl/d	US$43.99/Bbl	December 2020

Gas	Volume	Price	Remaining term
Ventura Swaps (Sale) (1)	20,000 MMBtu/d	US$1.69/MMBtu	August 2020 – October 2020
Chicago Swaps (Sale) (1)	20,000 MMBtu/d	US$1.71/MMBtu	August 2020 – October 2020
NYMEX Swaps (Sale)	20,000 MMBtu/d	US$2.17/MMBtu	September 2020
NYMEX Swaps (Sale)	10,000 MMBtu/d	US$2.93/MMBtu	November 2020 – March 2021
NYMEX Swaps (Sale)	40,000 MMBtu/d	US$2.68/MMBtu	January 2021 – December 2021
Dawn fixed-price physical	54,956 MMBtu/d	US$1.60/MMBtu	August 2020
Dawn fixed-price physical	45,000 MMBtu/d	US$1.56/MMBtu	September 2020
AECO fixed-price physical	90,000 GJ/d	CDN$1.66/GJ	July 2020 – October 2020
AECO fixed-price physical	35,000 GJ/d	CDN$1.80/GJ	August 2020
AECO fixed-price physical	25,000 GJ/d	CDN$1.85/GJ	September 2020
AECO fixed-price physical	10,000 GJ/d	CDN$2.65/GJ	November 2020 – March 2021
AECO fixed-price physical	20,000 GJ/d	CDN$2.50/GJ	January 2021 – December 2021

(1) These hedges swap physical sales of Alberta natural gas production from Chicago and Ventura index pricing to fixed prices.

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 second 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/1224861/Paramount_Resources_Ltd.pdf

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)

		Q2 2020		Q1 2020
Net loss		**(75.7)**		(235.1)
per share – basic and diluted ($/share)		***(0.57)***		*(1.76)*
Cash from (used in) operating activities		**(14.2)**		30.5
per share – basic and diluted ($/share)		***(0.11)***		*0.23*
Adjusted funds flow		**19.0**		33.5
per share – basic and diluted ($/share)		***0.14***		*0.25*
Total assets		**3,066.4**		3,009.5
Long-term debt		**754.9**		651.5
Net debt		**810.7**		771.9
Common shares outstanding *(thousands)*(2)		**133,784**		133,346
Sales volumes				
Natural gas (MMcf/d)		**253.2**		261.5
Condensate and oil (Bbl/d)		**22,823**		21,898
Other NGLs (Bbl/d) (3)		**3,817**		4,539
Total (Boe/d)		**68,839**		70,022
% liquids		***39%***		*38%*
Grande Prairie Region (Boe/d)		**31,039**		28,214
Kaybob Region (Boe/d)		**29,561**		32,700
Central Alberta and Other Region (Boe/d)		**8,239**		9,108
Total (Boe/d)		**68,839**		70,022
Netback		*$/Boe (4)*		*$/Boe (4)*
Natural gas revenue	**44.7**	***1.94***	53.6	*2.25*
Condensate and oil revenue	**60.3**	***29.05***	111.4	*55.92*

Other NGLs revenue (3)	**4.3**	***12.28***	4.4	*10.75*
Royalty and sulphur revenue	**3.9**	[illegible]	2.7	–
Petroleum and natural gas sales	**113.2**	***18.07***	172.1	*27.01*
Royalties	**(3.6)**	***(0.57)***	(11.7)	*(1.84)*
Operating expense	**(62.6)**	***(9.99)***	(92.3)	*(14.49)*
Transportation and NGLs processing (5)	**(25.3)**	***(4.04)***	(23.6)	*(3.70)*
Netback	**21.7**	***3.47***	44.5	*6.98*
Commodity contract settlements	**12.9**	***2.05***	7.0	*1.10*
Netback including commodity contract settlements	**34.6**	***5.52***	51.5	*8.08*
Total Capital Expenditures				
Grande Prairie Region		**36.7**		49.8
Kaybob Region		**1.8**		10.1
Central Alberta and Other Region		**0.8**		2.8
Corporate		**1.5**		1.1
Land and property acquisitions		**0.6**		–
Total capital expenditures		**41.4**		63.8
Asset retirement obligation settlements		**4.0**		30.3

(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): Q2 2020: 414 and Q1 2020: 852.
(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 second half of 2020;
- planned exploration, development and production activities;
- estimated and anticipated DCET and drilling costs;
- expected GHG reductions associated with controller upgrades and reduced trucking;
- planned abandonment and reclamation expenditures in 2021 using funding under the Alberta Site Rehabilitation Program;
- expected reductions in costs and expenditures and the sustainability of cost reductions; and
- the expectation that two additional water disposal wells will meet Karr area development needs for the foreseeable future.

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; 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 months ended June 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;
- 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, 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, reorganization costs, asset retirement obligation settlements 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 June 30, 2020 and March 31, 2020:

Three months ended	Jun 30, 2020 (MM$)	Mar 31, 2020 (MM$)
Cash from (used in) operating activities	**(14.2)**	**30.5**
Change in non-cash working capital	24.0	(34.3)
Geological and geophysical expenses	1.9	2.6
Asset retirement obligations settled	4.0	30.3
Reorganization costs	3.0	-
Provision and other	0.3	4.4
Adjusted funds flow	**19.0**	**33.5**

"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 six months ended June 30, 2020, the value ratio between crude oil and natural gas was approximately 22:1. 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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