Paramount Resources Ltd.

Paramount Resources Ltd. Reports Third Quarter 2019 Results

CALGARY, Nov. 7, 2019 /CNW/ -

HIGHLIGHTS

- Paramount's sales volumes averaged 81,046 Boe/d in the third quarter of 2019, relatively unchanged from the second quarter. Third quarter liquids sales volumes, however, increased 1,441 Bbl/d to 31,612 Bbl/d (39 percent of total sales) compared to 30,171 Bbl/d (37 percent of total sales) in the second quarter.
- At Wapiti, third quarter sales volumes increased 109 percent to 8,163 Boe/d (74 percent liquids) compared to the second quarter.
- All 11 (11.0 net) Montney wells on the Wapiti 9-3 pad have started-up and are producing at restricted rates largely due to intermittent, but improving, runtime associated with the commissioning of the new third-party Wapiti natural gas processing facility (the "Wapiti Plant"). Under those operating conditions, the 11 wells averaged gross peak 30-day production of 1,198 Boe/d per well, with average CGRs of 378 Bbl/MMcf.[(1)]
- At the new 5-3 pad in Wapiti, three of 12 (12.0 net) wells were temporarily brought-on production through inline test facilities in late-September. The remaining wells are being flowed on cleanup on a rotational basis to recover completion fluids prior to the installation of permanent surface facilities. Initial flowback results have demonstrated higher production rates than the 9-3 pad.
- At Karr, 5 (5.0 net) new Montney wells were started-up on the 4-24 pad in late-September, averaging 2,027 Boe/d of gross peak 30-day production per well, with an average wellhead CGR of 339 Bbl/MMcf.[(1)]
- Paramount is increasing its fourth quarter 2019 production guidance to between 87,000 Boe/d and 90,000 Boe/d.
- The Company's third quarter netback was $68.2 million compared to $82.1 million in the second quarter of 2019, mainly due to lower commodity prices and incremental third-party processing fees following the sale of the Karr 6-18 natural gas processing facility (the "6-18 Facility") in August.[(2)]
- Cash from operating activities was $48.6 million in the third quarter of 2019. Adjusted funds flow was $50.9 million ($0.39 per share).[(2)]
- Base capital spending totaled $113.1 million for the third quarter and $265.0 million for the nine months ended September 30, 2019, with capital programs at Wapiti and Central Alberta coming in under budget. As a result of capital efficiencies realized to date in the 2019 program, the Company has accelerated drilling operations for 10 (10.0 net) Montney wells at Karr into the fourth quarter of 2019 that were originally scheduled for 2020, while maintaining its 2019 base capital budget at $350 million.[(2)]
- The Company commenced its first area-based closure ("ABC") abandonment and reclamation project in the third quarter at Hawkeye. Economies of scale gained under the ABC approach have resulted in significantly lower costs than prior estimates. The Company's undiscounted estimated asset retirement obligation was revised down by approximately $140 million from December 31, 2018 to September 30, 2019.

---

(1) Production measured at the wellhead. Natural gas sales volumes are lower by approximately 14 percent (Karr) and 11 percent (Wapiti) and Wellhead Liquids sales volumes are lower by approximately 12 percent (Karr) and 3 percent (Wapiti) 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. See "Oil and Gas Measures and Definitions" in the Advisories.

(2) Netback, adjusted funds flow and base capital are non-GAAP measures. See "Non-GAAP Measures" in the Advisories.

CORPORATE

- Paramount's natural gas diversification strategy resulted in an average realized natural gas sales price of $1.58/Mcf in the third quarter, 46 percent higher than average AECO prices.
- In the third quarter of 2019, approximately 65 percent of Paramount's natural gas production was sold at AECO prices. The Company is well positioned to take advantage of the recent strengthening of market fundamentals in Alberta. In October 2019, the Company entered into AECO fixed-price physical contracts to sell 40,000 GJ/d of natural gas at $2.34/GJ for winter 2019/2020 and 60,000 GJ/d of natural gas at $1.56/GJ for summer 2020.
- Paramount closed the sale of its Karr 6-18 Facility for net cash proceeds of$327.6 million in August 2019.
- The Company's long-term debt balance at September 30, 2019 was $720.9 million. Paramount has a $1.5 billion bank credit facility that matures in November 2022.
- To date, the Company has purchased and cancelled 2.6 million Paramount common shares under its 2019 normal course issuer bid program (the "2019 NCIB") at a total cost of $14.4 million. These purchases were mainly funded by the disposition of a portion of the Company's investment in MEG Energy Corp.

REVIEW OF OPERATIONS

Paramount's sales volumes averaged 81,046 Boe/d in the third quarter of 2019, relatively unchanged from the second quarter. Liquids volumes increased to 31,612 Bbl/d (39 percent of total sales) in the third quarter compared to 30,171 Bbl/d (37 percent of total sales) in the second quarter. Liquids-rich production continued to ramp-up at both Wapiti and Kaybob South Duvernay. Third quarter production at Karr and Kaybob was impacted by planned facilities outages as well as the temporary shut-in of certain dry gas wells, as the Company proactively managed seasonally low natural gas prices.

Cash from operating activities was $48.6 million in the third quarter of 2019 compared to $48.1 million in the second quarter. Third quarter adjusted funds flow was $50.9 million ($0.39 per share) compared to $54.2 million ($0.41 per share) in the second quarter of 2019. Adjusted funds flow was impacted by lower realized prices and incremental third-party processing fees following the sale of the Karr 6-18 Facility.

Paramount permanently shut down its dry gas Hawkeye property in late-2018 and its Zama property in the first half of 2019 due to challenging economics. The closure of Zama is expected to reduce the Company's total operating expenses by approximately $27 million per year. The Company has permanently shut-in approximately 2,100 Boe/d of uneconomic production since the fourth quarter of 2018.

Base capital spending totaled $113.1 million for the third quarter and $265.0 million for the nine months ended September 30, 2019, with capital programs at Wapiti and Central Alberta coming in under budget. As a result of capital efficiencies realized to date in the 2019 program, the Company has accelerated drilling operations for 10 (10.0 net) Montney wells at Karr into the fourth quarter of 2019 that were originally scheduled for 2020, while maintaining its 2019 base capital budget at $350 million.

GRANDE PRAIRIE REGION

Karr

	Q3 2019		Q2 2019	
Sales volumes				
Natural gas (MMcf/d)		**58.3**		68.5
Condensate and oil (Bbl/d)		**8,712**		8,858
Other NGLs (Bbl/d)		**1,117**		1,505
Total (Boe/d)		**19,542**		21,782
% liquids		***50%***		*48%*
Netback	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*
Petroleum and natural gas sales	**63.3**	***35.24***	72.0	*36.32*
Royalties	**(5.7)**	***(3.15)***	(9.8)	*(4.90)*
Operating expense	**(27.8)**	***(15.47)***	(20.1)	*(10.14)*
Transportation and NGLs processing	**(6.6)**	***(3.66)***	(5.2)	*(2.65)*
	23.2	***12.96***	36.9	*18.63*

Third quarter 2019 sales volumes at Karr averaged 19,542 Boe/d compared to 21,782 Boe/d in the second quarter of 2019. Third quarter production at Karr was impacted for 12 days by scheduled processing facility outages and the temporary shut-in of two wells for approximately six weeks due to offsetting completion activities at the 4-24 pad.

The third quarter decrease in Karr netbacks was mainly the result of lower production, incremental third-party processing fees and higher water disposal costs. Incremental processing fees at the 6-18 Facility represented approximately $2.85 per Boe of third quarter per-unit operating costs for Karr alone and $0.70 per Boe for the Company.

At the 4-24 pad, 5 (5.0 net) new Montney wells were completed and brought-on production in late-September, exhibiting very strong initial performance, averaging 2,027 Boe/d of gross peak 30-day production per well with a CGR of 339 Bbl/MMcf.[(1)] Completion costs for these wells averaged $6.8 million per well compared to budgeted type-well completion costs of $7.7 million.

Paramount has also drilled 3 (3.0 net) new Montney wells on the 1-19 pad, which are scheduled to be brought on-stream late in the fourth quarter. Karr area sales volumes are expected to increase through the balance of the year as new production ramps up on the 4-24 and 1-19 pads.

In the fourth quarter of 2019, the Company commenced drilling operations for 10 (10.0 net) Montney wells that were originally scheduled for 2020. Paramount's focus on continuous improvement resulted in a new pacesetter well drilling cost of approximately $2.9 million, which compares to budgeted Karr type-well drilling costs of $4.0 million per well.

These ten new Karr wells will be completed and brought-on production in 2020, once the third-party midstream operator completes its expansion of the 6-18 Facility. Paramount is also investing in additional water injection facilities in 2020 to add incremental water disposal capacity. As Karr production ramps up, the expansion of the 6-18 Facility is completed and new water injection facilities come on-stream, per-unit operating costs at Karr are expected to decrease.

(1) Production measured at the well head, see table on page 4.

The Company drilled its first Lower Montney well at Karr in 2018, and the 4-24 and 1-19 pads each include one Lower Montney well. The results of these three wells will be incorporated in Paramount's assessment of total Montney well location inventory, in the context of optimizing recoveries and capital efficiencies.

Montney wells at Karr continue to exhibit strong production rates and condensate yields. The following table summarizes the performance of wells on the 4-24 and 1-2 pads, and the 27 wells drilled in the 2016/2017 capital program:

	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)*	
4-24 Pad							
00/01-11-065-06W6/0 (4)	1,878	1,271	349	89	59	328	50
00/02-12-065-06W6/0	1,836	1,308	413	83	59	410	50
02/03-12-065-06W6/0	2,029	1,308	302	110	69	280	57
00/04-12-065-06W6/0	2,084	1,320	288	114	69	256	57
00/03-12-065-06W6/0	2,307	1,584	365	139	91	316	64
1-2 Pad							
02/01-26-065-05W6/0	2,108	1,333	287	431	245	220	360
02/04-25-065-05W6/0	1,703	951	211	484	231	152	393
00/02-26-065-05W6/0	2,058	1,286	278	627	351	212	405
00/04-25-065-05W6/0 (4)	1,598	975	261	400	227	219	411
00/01-26-065-05W6/0	1,878	1,180	282	551	301	201	412
2016/2017 Wells							
27 wells (Avg. per well)	1,971	1,186	252	650	333	175	659

(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 14 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 October 31, 2019. Natural gas sales volumes are approximately 14 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.

(4) Lower Montney well.

Wapiti

Sales volumes at Wapiti averaged 8,163 Boe/d in the third quarter of 2019, comprised of 13.0 MMcf/d of natural gas and 6,002 Bbl/d of liquids, and generated a netback of $14.2 million ($18.94 per Boe). Intermittent production during the commissioning of the new third-party Wapiti Plant resulted in higher fuel gas and shrink losses. These impacts are expected to diminish as operations at the Wapiti Plant stabilize and throughput increases. Third quarter 2019 capital spending at Wapiti was $61.2 million, focused on completion operations at the 5-3 pad, which came in significantly under budget.

All 11 (11.0 net) wells on the Company's first pad at Wapiti, the 9-3 pad, have been brought- on production. This 11-well pad consists of a six-well block drilled to the south and a five-well block drilled to the north. The north and south blocks are specifically designed to test landing zone and spacing patterns. Completion costs for the 9-3 pad averaged $5.5 million per well, compared to budgeted Wapiti type-well completion costs of $7.8 million.

Initial production rates for these wells were impacted by an extended cycle time between completion operations and initial flowback, tubular limitations and intermittent production due to infrastructure capacity restrictions and commissioning activities at the Wapiti Plant. These early operational challenges have been largely alleviated and runtime and production rates have stabilized. Despite the operational challenges encountered with start-up, these wells have exhibited significantly higher CGRs than third-party offsetting wells which utilized a different completion design. The wells on the 9-3 pad are Paramount's first Wapiti wells fracked with the same completion design as utilized at Karr, which have also exhibited higher long-term production rates and higher CGRs than offsetting third-party wells.

The following table summarizes the performance to date of the 11 Montney wells on the 9-3 pad:

	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)*	
9-3 Pad							
02/06-15-068-06W6/0	1,511	1,088	429	66	48	444	50
00/11-27-067-06W6/0	1,360	880	306	95	61	299	90
02/07-15-068-06W6/0	1,192	815	360	112	77	367	133
03/08-15-068-06W6/0	962	689	421	99	72	444	133
02/08-15-068-06W6/0	969	693	418	106	73	369	137
02/10-27-067-06W6/0	1,137	779	363	133	89	337	138
03/10-27-067-06W6/0	1,111	749	345	140	87	274	155
03/07-15-068-06W6/0	1,042	787	514	120	83	374	156
02/09-27-067-06W6/0	1,094	769	394	150	100	333	158
03/09-27-067-06W6/0	1,268	794	279	185	121	315	174
04/09-27-067-06W6/0	1,536	1,102	423	191	123	301	175

(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 October 31, 2019. 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. 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.

The new 5-3 pad at Wapiti includes 12 (12.0 net) Montney wells. The Company achieved a new pacesetter drill cost of approximately $2.6 million for one of these wells, compared to budgeted type-well drilling costs of $3.5 million per well.

Three of the twelve wells on the 5-3 pad were brought-on production through inline test facilities in late-September, and three additional wells were started-up in October. The remaining wells are also scheduled to flowback on a rotational basis to recover completion fluids and prepare for the installation of permanent surface facilities. Initial flowback results have demonstrated higher initial production rates than the 9-3 pad, primarily due to flowing without tubular restrictions and a shorter cycle time between completion operations and initial flowback. The following table summarizes the initial production results for six of the wells that have produced to date:

	Last Day of Production (1)			Cumulative (2)				Days on Production
	Total	Wellhead Liquids	CGR (3)	Average	Total	Wellhead Liquids	CGR (3)	
	(Boe/d)	*(Bbl/d)*	*(Bbl/MMcf)*	*(Boe/d)*	*(MBoe)*	*(MBbl)*	*(Bbl/MMcf)*	
5-3 Pad								
00/09-28-067-06W6/0	1,893	1,336	400	1,501	9	7	465	6
02/11-27-067-06W6/0	2,042	1,432	391	1,975	23	17	445	12
00/12-27-067-06W6/0	1,869	1,281	363	1,805	24	17	398	14
02/12-27-067-06W6/0	2,064	1,296	281	2,071	33	21	310	16
03/11-27-067-06W6/0	2,620	1,612	267	2,021	46	30	317	23
02/09-28-067-06W6/0	1,538	939	261	1,412	57	36	296	40

(1) Volumes measured on October 31, 2019, or the last day the well was produced. Production 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. The production rates and volumes shown are over a single day and, therefore, are not necessarily indicative of average daily production, long-term performance or of ultimate recovery from the wells. See "Oil and Gas Measures and Definitions" in the Advisories.

(2) Cumulative is the aggregate production measured at the wellhead to October 31, 2019. 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. 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 34,615 Boe/d (31 percent liquids) in the third quarter of 2019 compared to 37,127 Boe/d (31 percent liquids) in the second quarter of the year. Sales volumes were lower in the third quarter as a result of base declines, scheduled facility outages and the temporary shut-in of dry gas wells due to low gas prices, partially offset by increased production at Kaybob South Duvernay.

Kaybob South Duvernay

At Kaybob South Duvernay, 5 (2.5 net) new wells on the 2-28 pad were drilled between June 2018 and January 2019 and completed in the spring of 2019. These wells were tied-in and brought-on production in June 2019, averaging 1,222 Boe/d of gross peak 30-day production per well, with an average wellhead CGR of 171 Bbl/MMcf.(1) To date, these wells have an average cumulative CGR of 158 Bbl/MMcf.(2)

Kaybob Smoky Duvernay

In the fourth quarter of 2018, the Company brought 4 (4.0 net) new wells on production on the 10-35 pad at Kaybob Smoky Duvernay through Paramount's Smoky 06-16 gas plant. These wells are continuing to exceed internal type curve estimates. The following table summarizes the performance of the four wells on the 10-35 pad:

---

(1) Production measured at the wellhead. Natural gas sales volumes are approximately 13 percent lower and Wellhead Liquids sales volumes are approximately 22 percent lower 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. See ”Oil and Gas Measures and Definitions” in the Advisories.

(2) CGR means condensate to gas ratio and is calculated by dividing raw Wellhead Liquids volumes by raw wellhead natural gas volumes. The stated CGRs exclude days when the wells did not produce. Average cumulative gross production for five wells: 115 MBoe total production, 56 Mbbls of liquids. In aggregate the five wells have produced for a total of 604 days. CGRs stated are over a short period of time and, therefore, are not necessarily indicative of long-term performance.

	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)*	
10-35 Pad							
00/09-25-063-21W5/2	1,150	779	350	210	132	282	319
02/01-25-063-21W5/0	1,303	728	211	332	194	234	324
00/16-25-063-21W5/0	1,452	998	366	237	153	304	343
00/08-25-063-21W5/0	1,345	897	334	289	169	235	370

(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 12 percent lower and Wellhead Liquids sales volumes are approximately 3 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, 2019. Natural gas sales volumes are approximately 12 percent lower and Wellhead Liquids sales volumes are approximately 3 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.

Ante Creek Montney

The Kaybob Region drilling program for 2019 included an initial Montney appraisal well at Ante Creek. This well was completed and brought-on production in September. Initial production results are encouraging and continue to be evaluated.

CENTRAL ALBERTA AND OTHER REGION

Central Alberta and Other Region sales volumes averaged 18,504 Boe/d in the third quarter of 2019 compared to 18,862 Boe/d in the second quarter of 2019. The Company participated in one (0.5 net) well at Birch in northeast British Columbia, which was completed and brought-on production in the second quarter.

Paramount completed the full shut-down of Zama area production in June 2019. The closure program will continue into 2020 to permanently suspend all facilities and over 2,000 kilometers of pipelines. The closure of Zama is expected to reduce the Company's total operating expenses by approximately $27 million per year.

The Company commenced its first ABC project in the third quarter at Hawkeye. Economies of scale gained under the ABC approach have resulted in significantly lower costs than prior estimates. Paramount will continue to optimize its abandonment and reclamation activities based on the actual experience and knowledge gained from this and other projects and pursue additional opportunities to further reduce costs on an on-going basis. The Company's undiscounted estimated asset retirement obligation was revised from $1.79 billion as at December 31, 2018 to $1.65 billion as at September 30, 2019, and from $807.9 million to $749.1 million on a discounted basis.

GREENHOUSE GAS REDUCTION INITIATIVE

As part of Paramount's commitment to responsible energy development, the Company is participating in greenhouse gas ("GHG") emission reduction programs and investing in new equipment to reduce the emission of GHG from its operations. In addition, the Company has reduced its total emissions with the retirement of three facilities at Zama in 2019.

In the Kaybob and Central Alberta and Other Regions, Paramount has recently completed a GHG project, under budget and ahead of schedule, which included the replacement of approximately 1,700 high-bleed controllers with modern low-bleed units at a total cost of $3.0 million. These low-bleed controllers are expected to eliminate approximately 120,000 tonnes of GHG emissions annually. The project is anticipated to generate approximately $9.0 million in GHG credits under current regulations through 2022.

Planning has also commenced for upgrades to the Company's remaining high-bleed controllers and certain other equipment to reduce emissions of GHGs, including methane, carbon dioxide, and nitrogen oxides.

CORPORATE

Paramount has 16,000 Bbl/d of liquids hedged for the remainder of 2019 at an average price of $78.05/Bbl and 4,000 Bbl/d of liquids for 2020 at an average price of $80.11/Bbl.

Paramount's natural gas diversification strategy includes approximately 122,000 GJ/d of sales under long-term contracts priced at the Dawn, US Midwest and Malin markets. The Company's average realized natural gas sales price for the third quarter of 2019 was $1.58/Mcf, approximately 46 percent higher than average AECO prices.

In the third quarter of 2019, approximately 65 percent of Paramount's natural gas production was sold at AECO prices. The Company is well positioned to take advantage of the recent strengthening of market fundamentals, which have resulted in sharp increases in Alberta natural gas prices. In October 2019, Paramount entered into AECO fixed-price physical contracts to sell 40,000 GJ/d of natural gas at $2.34/GJ for winter 2019/2020 and 60,000 GJ/d of natural gas at $1.56/GJ for summer 2020.

The Company's debt balance at September 30, 2019 was $720.9 million. Paramount has a $1.5 billion bank credit facility that matures in November 2022.

In January 2019, Paramount implemented the 2019 NCIB, under which the Company may purchase up to 7.1 million shares for cancellation. To date, the Company has purchased and cancelled 2.6 million common shares at a total cost of $14.4 million under the 2019 NCIB. These purchases were mainly funded by the disposition of a portion of the Company's investment in MEG Energy Corp.

FINANCIAL AND OPERATING RESULTS [1]

($ millions, except as noted)

	Q3 2019	Q2 2019
Net income (loss)	**141.0**	(121.0)
per share – basic and diluted ($/share)	***1.08***	*(0.93)*
Cash from operating activities	**48.6**	48.1
Adjusted funds flow	**50.9**	54.2
per share – basic and diluted ($/share)	***0.39***	*0.41*
Total assets	**3,771.1**	4,031.8
Long-term debt	**720.9**	909.7
Net debt	**777.9**	964.8
Common shares outstanding *(thousands)*	**130,879**	130,912
Sales volumes		
Natural gas (MMcf/d)	**296.6**	309.7
Condensate and oil (Bbl/d)	**24,761**	23,312

Other NGLs (Bbl/d) (3)		**6,851**		6,859
Total (Boe/d)		**81,046**		81,793
% liquids		***39%***		*37%*
Grande Prairie Region (Boe/d)		**27,927**		25,804
Kaybob Region (Boe/d)		**34,615**		37,127
Central Alberta and Other Region (Boe/d)		**18,504**		18,862
Total (Boe/d)		**81,046**		81,793
Netback		*$/Boe (2)*		*$/Boe (2)*
Natural gas revenue	**43.1**	***1.58***	49.5	*1.76*
Condensate and oil revenue	**149.7**	***65.73***	150.7	*71.02*
Other NGLs revenue (3)	**6.2**	***9.78***	6.9	*11.01*
Royalty and sulphur revenue	**0.8**	–	2.1	–
Petroleum and natural gas sales	**199.8**	***26.80***	209.2	*28.10*
Royalties	**(12.1)**	***(1.62)***	(18.7)	*(2.51)*
Operating expense	**(93.8)**	***(12.58)***	(86.8)	*(11.66)*
Transportation and NGLs processing (4)	**(25.7)**	***(3.45)***	(21.6)	*(2.91)*
Netback	**68.2**	***9.15***	82.1	*11.02*
Commodity contract settlements	**5.7**	***0.76***	(2.8)	*(0.37)*
Netback including commodity contract settlements	**73.9**	***9.91***	79.3	*10.65*
Base Capital (5)				
Grande Prairie Region		**106.6**		56.2
Kaybob Region		**5.4**		29.2
Central Alberta and Other Region		**1.1**		0.4
Total		**113.1**		85.8
Asset retirement obligations settlements		**3.6**		2.0

(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: Net Debt, Netback, Adjusted Funds Flow and Base Capital.
(2) Natural gas revenue presented as $/Mcf.
(3) Other NGLs means ethane, propane and butane.
(4) Includes downstream transportation costs and NGLs fractionation costs.
(5) Excludes spending related to the expansion of the 6-18 Facility prior to its sale, land and property acquisitions and corporate expenditures.

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 resources. The Company also pursues long-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 2019 results, including Management's Discussion and Analysis and the Company's Consolidated Financial Statements, can be obtained at: https://mma.prnewswire.com/media/1024971/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.

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:

- expected average sales volumes in the fourth quarter of 2019;
- budgeted capital expenditures and the maintenance of the 2019 base capital budget at $350 million;
- the expected increase in sales volumes at Karr for the balance for the year as additional new wells are brought-on

production;
- an expected decrease in per unit operating costs at Karr;
- an expected decrease in the impact of higher fuel gas and shrink losses at Wapiti as operations at the Wapiti Plant stabilize and throughput increases;
- the timing of completion of the 6-18 Facility expansion;
- the scheduled completion of the Zama closure program and the anticipated reduction in future operating costs;
- planned GHG reduction measures and expenditures and expected GHG credits; and
- planned exploration, development and production activities, including the anticipated timing of bringing new wells on production.

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;
- 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;
- 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 application of regulatory requirements respecting abandonment and reclamation, GHG emissions and GHG credits; and
- anticipated timelines and budgets being met in respect of drilling programs and other operations (including well completions and tie-ins and the construction, commissioning and start-up of new and expanded facilities, including third-party facilities).

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 natural gas and liquids prices;
- 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 section titled "*Risk Factors*" in Paramount's annual information form for the year ended December 31, 2018, 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.

Non-GAAP Measures

In this press release, "Adjusted funds flow", "Netback", "Net debt" and "Base capital", collectively 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 operating activities before net changes in operating non-cash working capital, geological and geophysical expenses, asset retirement obligation settlements, closure cost expenditures 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 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 settling its asset retirement obligations and, as a result, amounts incurred may vary 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 is the calculation of adjusted funds flow from the nearest GAAP measure for the three months ended September 30, 2019 and June 30, 2019:

	Q3 2019	Q2 2019
Cash from operating activities	48.6	48.1
Change in non-cash working capital	(8.7)	(2.4)
Geological and geophysical expenses	2.5	2.1
Closure cost expenditures	4.9	4.4
Asset retirement obligations settled	3.6	2.0
Adjusted funds flow	50.9	54.2

"Netback" equals petroleum and natural gas sales less royalties, operating costs 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. The following is the calculation of netback from the nearest GAAP measure for the three months ended September 30, 2019 and June 30, 2019:

	Q3 2019	Q2 2019
Petroleum and natural gas sales	199.8	209.2
Royalties	(12.1)	(18.7)
Operating expense	(93.8)	(86.8)
Transportation and NGLs processing	(25.7)	(21.6)
Netback	68.2	82.1

"Net debt" is a measure of the Company's overall debt position after adjusting for certain working capital amounts and is used by management to assess the Company's overall leverage position. The following is the calculation of net debt from the nearest GAAP measure as at September 30, 2019 and June 30, 2019:

As at	September 30, 2019	June 30, 2019
Cash and cash equivalents	(11.1)	(19.3)
Accounts receivable	(91.9)	(98.3)
Prepaid expenses and other	(16.4)	(16.1)
Accounts payable and accrued liabilities	176.4	188.8
Adjusted working capital deficit (1)	57.0	55.1
Paramount Facility	720.9	909.7
Net Debt	777.9	964.8

(1) Adjusted working capital excludes risk management assets and liabilities, current accounts receivable amounts relating to subleases (September 30, 2019 - $2.1 million, June 30, 2019 - $2.0 million) and the current portion of asset retirement obligations and other.

"Base capital" consists of the Company's spending on wells, infrastructure projects, other property, plant and equipment and exploration and evaluation assets and excludes spending related to the expansion of the 6-18 Facility prior to its sale, land and property acquisitions and corporate assets. The exploration and development capital measure provides management and investors with information regarding the Company's capital spending on wells and infrastructure projects separate from land and property acquisition activity and corporate expenditures. The following is a reconciliation of base capital to the nearest GAAP measure for the three months ended September 30, 2019 and June 30, 2019 and for the nine months ended September 30, 2019:

	Three months ended September 30,2019	Three months ended June 30,2019	Nine months ended September 30,2019
Property, plant and equipment and exploration	127.5	100.3	331.9
Karr 6-18 Facility expansion	–	(11.0)	(45.5)
Land and property acquisitions	(1.9)	(3.3)	(6.2)
Corporate	(12.5)	(0.2)	(15.2)
Base capital	113.1	85.8	265.0

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
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
NYMEX	New York Mercantile Exchange

This press release contains disclosures expressed as "Boe", "$/Boe", "MBoe" 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, 2019, the value ratio between crude oil and natural gas was approximately 53:1. 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 contains metrics commonly used in the oil and natural gas industry. Each of these metrics is determined by the Company as set out below or elsewhere in this press release. "CGR" means condensate to gas ratio and is calculated by dividing raw Wellhead Liquids volumes by raw wellhead natural gas volumes. ”Wellhead Liquids” means oil, condensate and other hydrocarbon liquids. CGR 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.

SOURCE Paramount Resources Ltd.

For further information: Paramount Resources Ltd., J.H.T. (Jim) Riddell, Chairman and President and Chief Executive Officer; B.K. (Bernie) Lee, Executive Vice President, Finance and Chief Financial Officer; Rodrigo (Rod) Sousa, Executive Vice President, Corporate Development and Planning, www.paramountres.com, Phone: (403) 290-3600